Paramount resources ltd.

2004 Annual report

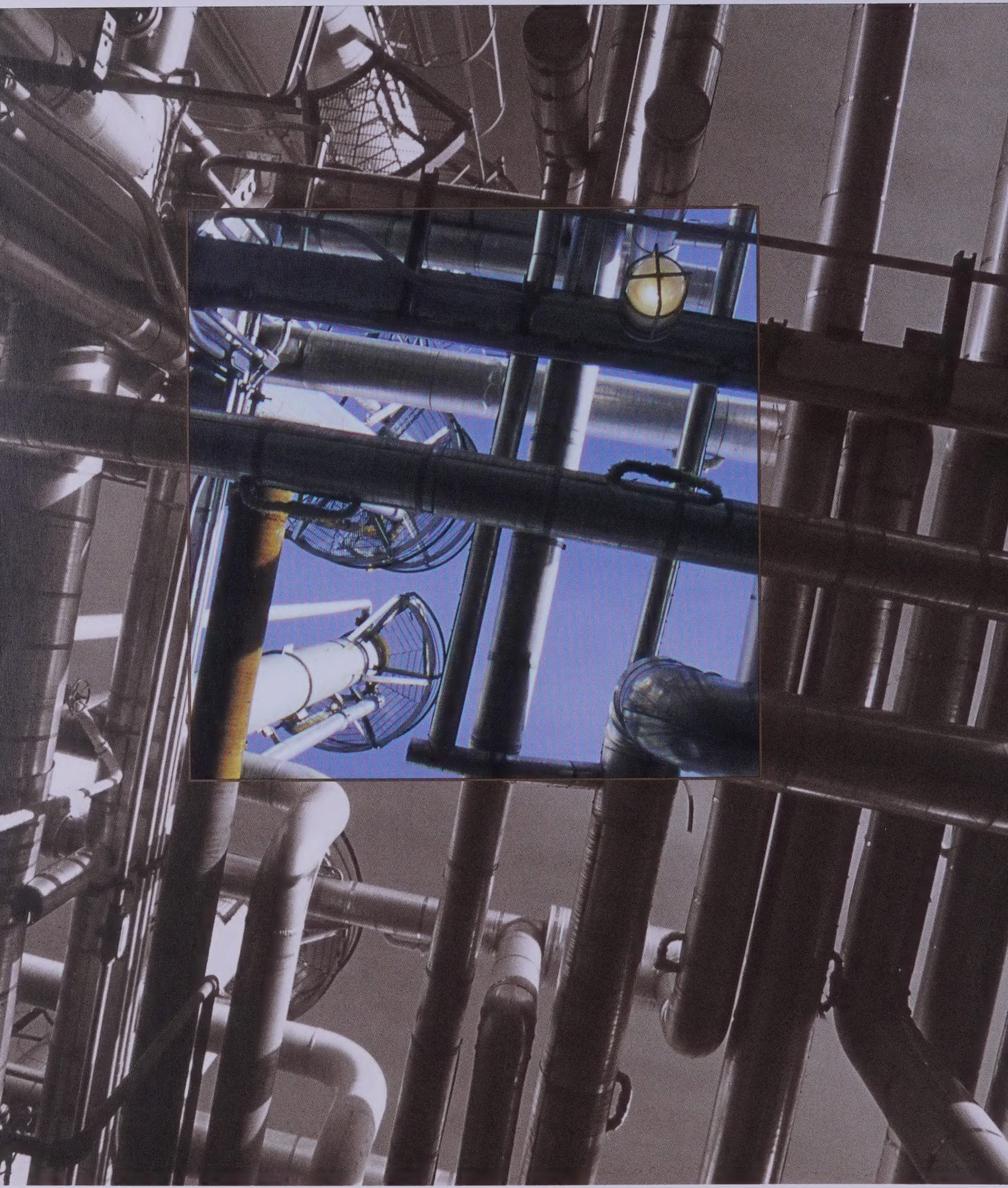
ANNUAL AND SPECIAL MEETING

Shareholders are cordially invited to attend the Annual Meeting to be held May 26, 2005, at 4:00 p.m.
Calgary Petroleum Club
Devonian Room
319 Fifth Avenue S. W.
Calgary, Alberta

FINANCIAL HIGHLIGHTS

($ thousands except per share amounts and where stated otherwise)	Year Ended December 31 2004	2003	% Change
FINANCIAL			
Petroleum and natural gas sales, net of transportation costs	**550,616**	434,059	27%
Cash flow (1)			
From operations	**295,566**	167,276	77%
Per share - basic	**4.95**	2.78	78%
- diluted	**4.84**	2.77	75%
Earnings			
Net earnings (loss)	**41,174**	1,151	3,477%
Per share - basic	**0.69**	0.02	3,350%
- diluted	**0.67**	0.02	3,250%
Capital expenditures (2)			
Exploration and development	**316,284**	223,753	41%
Acquisitions, dispositions and other (3)	**262,730**	(368,731)	171%
Net capital expenditures	**579,014**	(144,978)	498%
Total assets	**1,542,786**	1,177,130	31%
Net debt (4)	**451,187**	297,055	52%
Shareholders' equity	**625,039**	496,033	26%
Weighted average common shares outstanding (thousands)	**59,755**	60,098	(1)%
Common shares outstanding at year end (thousands)	**63,186**	60,095	5%
Common shares outstanding at March 8, 2005 (thousands)	**63,899**		
OPERATING			
Production			
Natural gas (MMcf/d)	**173**	153	13%
Crude oil and liquids (Bbl/d)	**7,297**	7,169	2%
Total production (Boe/d) @ 6:1	**36,150**	32,630	11%
Average prices (5)			
Natural gas (pre-financial instruments) ($/Mcf)	**6.72**	5.99	12%
Natural gas ($/Mcf) (6)	**6.86**	5.16	33%
Crude oil and liquids (pre-financial instruments) ($/Bbl)	**46.80**	38.27	22%
Crude oil and liquids ($/Bbl) (6)	**44.13**	35.50	24%
Reserves (proved plus probable)			
Natural gas (Bcf)	**568.6**	329.4	73%
Crude oil and liquids (MBbl)	**20,461**	12,513	64%
Estimated present value before tax (discounted @ 10% using forecasted prices and costs)			
Proved ($ millions)	**1,156.0**	597.4	94%
Proved and probable ($ millions)	**1,659.3**	733.6	126%
Land (thousands of acres)			
Total net land holdings	**4,082**	3,386	21%
Net undeveloped land holdings	**3,442**	2,800	23%
Drilling activity (gross)			
Gas	**229**	180	27%
Oil	**12**	16	(25)%
Oilsands evaluation (7)	**17**	-	100%
D&A	**13**	15	(13)%
Total wells	**271**	211	28%
Success rate (7)	**95%**	93%	2%

(1) Cash flow from operations is a non-GAAP term that represents net earnings adjusted for non-cash items, dry hole costs and geological and geophysical costs. The Company considers cash flow from operations a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future growth through capital investment and to repay debt.
(2) Excludes capital expenditures of discontinued operations and other minor accounting adjustments.
(3) 2003 disposition proceeds include the $51 million related to Paramount Energy Trust units.
(4) Net debt is equal to long-term debt including working capital, excluding discontinued operations.
(5) Average prices are net of transportation costs.
(6) Excludes non-cash gains and losses on financial instruments.
(7) Success rate excludes oilsands evaluation wells.



LETTER to SHAREHOLDERS

Paramount and its shareholders enjoyed an exceptional year in 2004 as the Company experienced one of the most active years in our 26 year history in virtually every aspect of our business. A review of the significant events throughout the year will show that the Company's exploration and development program was one of the largest ever undertaken by the Company. We also executed a series of significant acquisitions which have added to the production base as well as the exploration and development inventory. Financing these activities was achieved through a combination of different debt and equity instruments which maximized Paramount's return. Paramount is now poised on the brink of completing the spinout to its shareholders of its second distribution generating trust in as many years, ("Trilogy Energy Trust"), for the benefits of its shareholders. We are executing the business plan we laid out and the results are providing shareholders with superior, if not extraordinary returns.

The focus of Paramount's activity is the exploration and development program which in 2004 totalled $316.3 million. The majority of the activities were spread amongst the five main operating units in Kaybob, Grande Prairie, Northwest Alberta/Cameron Hills, Northwest Territories, Northeast British Columbia/Liard, Northwest Territories, and Southern Alberta. Additional spending was directed to furthering the long-term projects Paramount is pursuing in the Colville Lake area in the northern part of the Northwest Territories, and in the Athabasca Oil Sands area of northeast Alberta.

In Kaybob, Paramount started to see the results of years of work discovering, consolidating and developing the Lower Cretaceous Gething resource play. The initial program to downspace these gas pools, started in 2004, and the results of these infill drilling programs into these Gething pools have been superior. Wells drilled into existing gas pools have for the most part found virgin, or near virgin, reservoir pressures confirming Paramount's vision that we would be finding new reserves and increasing substantially the recoveries of these pools. Paramount's success rate for adding new producing gas wells was over 95 percent in 2004. It is this play type which will be the cornerstone of Trilogy Energy Trust. The extensive inventory of development opportunities is expected to provide stability and sustainability of reserves and production, and ultimately per unit distributions for the Trust. The extension of Paramount's activities to the west of Kaybob into the Deep Basin play also occurred with material additions to the land and prospect inventory in 2004 in what is now referred to as the West Kaybob area.

In the Grande Prairie Operating Unit, Paramount continued the development of our shallow Dunvegan discoveries at Mirage, extending this play substantially. As well, the tie in of the discovery at Marten Creek was completed in April, 2004 adding the first production from this area to Paramount. The acquisition of assets in this area in July was complimentary to our original discovery and has established Marten Creek as an area of material value. This area in the Marten Creek asset will comprise close to 11 percent of the initial production base of Trilogy Energy Trust.

The Northwest Alberta/Cameron Hills, Northwest Territories Operating Unit saw the follow-up development and tie in of the prior-year discovery at Haro, extending the pool boundary, increasing reserves and adding deliverability to the operating unit. Additional drilling and seismic activities in 2005 will build on this drilling success as well as further develop existing production in this area.

In Northeast British Columbia/Liard, Northwest Territories, the acquisition of the majority of the working interest and assumption of operatorship at West Liard has made Paramount the dominant producer in the North. Paramount's expertise is expected to provide the basis for leading development of the western Canadian Sedimentary Basin northward with Paramount realizing many of the opportunities in this new frontier.

In the Southern Operating Unit, Paramount initiated and completed the first delineation phase of the Coalbed Methane evaluation program. We drilled 20 wells for this resource at our Chain/Craigmyle property with results that have exceeded our expectations. Paramount is moving forward to fully develop Phase One of the Coalbed Methane program which includes up to an additional 88 wells and forecasts initial production of approximately 10 MMcf/d.

In the fall of 2004, Paramount released an update of the results of our exploration activities in the Colville Lake area of the Northwest Territories. Paramount's two initial discovery wells at Nogha tested natural gas at rates of 3 to 5 MMcf/d and the pool has been independently estimated to contain some 250 Bcf of possible reserves. Paramount is continuing with exploration activities in 2005 at Nogha, Maunoir Ridge and a new prospect at Turton Lake. We are exploring our options for bringing this gas to market.

In the Athabasca Oil Sands area, Paramount added a large amount of additional acreage and conducted a drilling program to refine our understanding of the bitumen accumulations on our lands. This program has continued into the current year to the point where Paramount hopes to be in a position to select the location of the Company's first prototype plant for SAG-D development and to submit the application for this project.

Acquisitions and divestitures played an important role in the growth of Paramount's production base and added to future growth opportunities. The Kaybob acquisition added production, a large land base and seismic inventory which we believe will be instrumental in growing the remaining assets of the West Kaybob Operating Unit into a substantial entity of its own. Two separate transactions in the Liard area allowed Paramount to consolidate its interests in its current production as well as become the largest working interest owner and operator of the Liard Nahanni discovery from 2000. Finally, the Marten Creek acquisition added production to our original discovery which has grown the area to a significant asset in itself. The acquisition also added some control to plant capacity and further drilling opportunities which will be pursued over the next several years.

These combined activities of exploration, acquisitions and development provided Paramount with exceptional growth in both production and reserves. Paramount's production in the fourth quarter of 2004 grew 43 percent when compared with the same period in the prior year. As well, Paramount replaced our 2004 production 4.6 times, and increased our overall reserves by 71 percent to 115 million barrels of oil equivalent for a cost of finding and development of $9.49 per barrel of oil equivalent. The net asset value of the Company, calculated using conservative estimates and historical costs, reflected these results with a 141 percent increase to $25.01 per share.

To finance our capital spending program and acquisition activities, Paramount has been active on both debt and equity fronts. In late 2003, Paramount completed its first debt issue raising US$175 million which gave us the flexibility to initiate the infill drilling program at Kaybob as well as repurchase approximately 1.6 million of common shares through our normal course issuer bid. A second debt issue was completed in June, 2004 raising US$ 125 million which was used to finance the acquisitions at Kaybob and Liard. Later in the year, Paramount completed an equity issue selling 4.5 million shares for gross proceeds of $116.5 million. Finally, the Company redeemed US$85.4 million of the Senior Notes debt under the equity claw provision of the debt indentures.

Late in the year, after reviewing the options available to Paramount, the Directors of Paramount unanimously approved management's recommendation to pursue the spinout of Trilogy Energy Trust. Upon completion of the Trust spinout, Paramount shareholders will own 100 percent of the post-reorganization Paramount and 81 percent of the outstanding units of Trilogy. Paramount will own the remaining 19 percent of the outstanding units of Trilogy. Shareholders will receive one trust unit for each existing common share. Based on the number of Paramount shares outstanding on February 25, 2005, there are expected to be approximately 63.9 million common shares of Paramount and 78.9 million units of Trilogy outstanding upon completion of the Trust spinout. Trilogy will indirectly own certain of Paramount's existing assets with current production of approximately 25,000 Boe/d (80 percent natural gas). These assets, in the Kaybob and Marten Creek areas of Alberta, are primarily low-risk, high working interest, lower decline properties that are geographically concentrated with numerous infill drilling opportunities and good access to infrastructure and processing facilities to be operated and controlled by Trilogy. The balance of Paramount's assets, consisting of its predominantly growth-oriented assets, will remain with Paramount. Current production from these assets is approximately 20,000 Boe/d (75 percent natural gas). Through Paramount, shareholders will participate in the potential upside of its remaining predominantly growth-oriented assets. Through

Trilogy, unitholders will receive regular distributions of cash derived from the cash flow produced by Trilogy's low-risk development assets. The first cash distribution of the Trust, expected to be $0.16 per Trust Unit, is expected to be paid on May 15, 2005 to unitholders of record on May 2, 2005. Due to Trilogy's extensive development drilling portfolio, it is anticipated that Trilogy will retain approximately 35 percent of its cash flow for capital expenditures with the remaining 65 percent of its cash flow being distributed to unitholders in monthly distributions. This extensive development drilling portfolio is expected to make Trilogy less reliant on the competitive acquisition market for developed assets in order to maintain and grow distributions. If the necessary securityholder and court approvals are obtained and other conditions are satisfied, the Trust spinout is expected to be completed on or about April 1, 2005.

Looking forward to 2005, we are striving for similar success to that which we enjoyed this past year. We continue to follow the business plan which we have developed, combining short-term growth from a lower risk prospect inventory and longer term larger developments which we expect to translate into material value for shareholders in the future. The current commodity environment for energy is very good and has easily kept pace with the increased costs in the business. Paramount has budgeted a total of $340 million for capital expenditures for 2005; of this, $100 million is to be directed to the Trilogy assets and the remaining $240 million will be directed to the properties retained by Paramount Resources Ltd. Trilogy's capital program is intended to entirely replace production and reserves. Paramount's capital program is designed to grow production to 25,000 Boe/d by the end of the year. Total cash flow in 2005 of the combined entities is estimated to be approximately $425 million or approximately $6.66 per share.

Jim Riddell
President and Chief Operating Officer
March 24, 2005


YK
NWT
LIARD, NWT/ NORTHEAST BRITISH COLUMBIA
Liard/ Maxhamish
465 Boe/d
Clarke Lake
860 Boe/d
Liard West
1,189 Boe/d
NORTHWEST ALBERTA
Bistcho Lake
1,276 Boe/d
Cameron Hills
1,829 Boe/d
Haro
497 Boe/d
Negus East
405 Boe/d
GRANDE PRAIRIE
Mirage
2,171 Boe/d
Saddle Hills
1,049 Boe/d
KAYBOB
Kaybob North
6,660 Boe/d
Pine Creek
3,447 Boe/d
Fox Creek
1,277 Boe/d
Two Creeks
2,326 Boe/d
BC
AB
SK
SOUTHERN ALBERTA/ MONTANA/ NORTH DAKOTA
Chain
910 Boe/d
Enchant/Sylvan Lake
772 Boe/d
Montana
291 Boe/d
North Dakota
616 Boe/d
WA
ID
MT
ND

CORE PRODUCING AREAS

KAYBOB

The levels of drilling and completion activity continued to increase in the Kaybob area throughout the year. At its peak during the fourth quarter, five drilling rigs and eight service rigs were active. Paramount participated in 26 (16.9 net) wells in the fourth quarter bringing the 2004 total to 75 (52.2 net) wells for the year, resulting in 66 (45.7 net) gas wells, 7 (6.2 net) oil wells and 2 (0.3 net) dry holes. Capital expenditures in the Kaybob Operating Unit, including facility additions and optimization projects, were $111 million, up from $68 million in 2003. An additional $18.1 million was spent acquiring Crown lands in 2004, adding additional opportunities to Paramount's prospect inventory.

On June 30, 2004, Paramount completed the acquisition of additional interests in the Kaybob area. This acquisition initially added 6,600 Boe/d of production and a large undeveloped land base principally in the Deep Basin area west of the Kaybob core production area. These undeveloped lands are complementary to Paramount's own land assets resulting in a large prospect inventory for future drilling. As well, a significant amount of seismic data was included in the transaction providing Paramount with a competitive advantage for evaluating drilling prospects, Crown land sales and farm-in opportunities.

Gas production in the Kaybob Operating Unit averaged 96 MMcf/d in 2004, up 20 percent from the 2003 average of 80 MMcf/d. Oil and natural gas liquids production was 4,091 Bbl/d for 2004, up 67 percent from the 2003 average of 2,451 Bbl/d. Kaybob production averaged 15,704 Boe/d in 2003 and grew to 20,157 Boe/d in 2004. In spite of average production declines of approximately 24 percent, we were able to increase production through our capital spending program, as well as through the acquisition. The properties acquired in the transaction averaged 6,130 Boe/d for the second half of 2004. Kaybob production for December 2004 averaged 108 MMcf/d and 5,600 Bbl/d of oil and natural gas liquids (23,600 Boe/d).

Operating costs in the Kaybob area increased from a 2003 average of $6.05/Bbl to $6.96/Bbl. This increase in operating costs is due in part to higher per unit costs of the acquired properties. In addition, we performed a number of workovers on the acquired properties in the fourth quarter of 2004 and further workovers are planned in 2005. It is anticipated that the operating costs will be reduced to approximately $6.50/Bbl in 2005.

Proved plus probable reserve additions in the Kaybob Operating Unit were 51.5 Bcf and 1.25 MMBbl (9.8 MMBoe) which replaces 2004 production of 35.3 Bcf and 1.5 MMBbl (7.38 MMBoe). Costs of finding and development, including future capital, for the proved plus probable reserve additions for the Kaybob area were $6.37/Boe in 2004 which is down from $9.66/Boe in 2003.

The proposed reorganization involves spinning off a portion of the Kaybob Operating Unit assets into Trilogy Energy Trust. These assets will be combined with the Marten Creek assets from the Grande Prairie Operating Unit to form the basis of Trilogy Energy Trust. The Paramount-operated producing assets and lands that will be moved from the Kaybob Operating Unit to Trilogy are characterized by concentrated, high working interest, liquids-rich gas. The lands are in an area that can be characterized by multi-zone potential and a combination of conventional oil and gas and tight gas reservoirs. Paramount feels that a large portion of these lands can be further developed by drilling additional wells into these known tight gas reservoirs. Paramount believes that it can continue to develop these reserves using the expertise that it has gained over the past ten years in this area, and maintain both reserves and production rates for a number of years with the existing prospect inventory.

GRANDE PRAIRIE

The Grande Prairie Operating Unit grew significantly in 2004. The Company drilled 57 (46.4 net) wells compared to 45 (29.9 net) wells drilled in 2003. Of the total wells drilled in 2004, 21.4 net wells have been tied in and are presently producing and 9.4 net gas wells have been tested and are currently waiting to be tied in. Capital expenditures totaled $58 million in 2004 as compared to $41 million in 2003.

Gas production in 2004 increased 125 percent to average 27 MMcf/d as compared to 12 MMcf/d in 2003. The increase was the result of the Marten Creek acquisition in August 2004 which added approximately 12 MMcf/d of natural gas production and the significant gas production growth in the Mirage area. Oil and natural gas liquids production decreased 67 percent to average 585 Bbl/d in 2004 as compared to 1,767 Bbl/d in 2003 as a result of the Sturgeon

Lake property disposition in October of 2003. The 2004 year-end production exit rate was 40 MMcf/d of natural gas and 400 Bbl/d of oil and natural gas liquids. The 2004 production rates were lower than expected primarily due to third-party infrastructure limitations and wet weather delaying operations. The delays postponed the addition of approximately 5 to 6 MMcf/d of natural gas production in the first quarter of 2005.

In 2004, Marten Creek was the most significant growth area in the Grande Prairie Operating Unit. The first seven wells of this new area were brought on production in March 2004 with initial rates of 5 MMcf/d. A facility expansion was completed in November 2004 to mitigate third-party facility limitations resulting in an increase in production to over 10 MMcf/d by year end. The acquisition in August added production resulting in a field exit rate that was over 20 MMcf/d. Paramount is planning to drill up to 12 wells in 2005, add a field compressor, expand the gathering system and add two water disposal wells to increase production. The Marten Creek project area will also be one of the initial properties to comprise the assets of Trilogy Energy Trust.

The Mirage area was Grande Prairie's most active area with 28 (25.1 net) wells drilled in 2004, two compressors installed and 44 sections of gross land added. Proved plus probable reserve additions at Mirage for 2004 were 4 Bcf. Mirage's 2004 exit production rate was 14 MMcf/d of natural gas and 250 Bbl/d of oil and natural gas liquids. The drilling operations in 2004 were delayed two to four months by wet weather, which also delayed a third-party gathering system expansion. The current standing wells are expected to be tied in by the end of the first quarter of 2005 and will initially produce approximately 6 MMcf/d. The growth in this field has been the result of the ongoing development of the shallow Dunvegan formation, as well as the success in new, slightly deeper formations.

NORTHWEST ALBERTA / CAMERON HILLS, NORTHWEST TERRITORIES

During the year, Paramount participated in the drilling of 22 (14.5 net) wells of which only 1 (0.5 net) well was dry and abandoned. Due to restricted seasonal access, the vast majority of field activities related to seismic acquisition, drilling, and construction were performed in the first quarter. Capital expenditures for the year totaled $32.6 million which was evenly split between drilling and facility expenditures.

For 2004, natural gas production averaged 20 MMcf/d of gas and 797 Bbl/d of oil and natural gas liquids, compared to 22 MMcf/d of natural gas and 448 Bbl/d of oil and NGLs in 2003. Significant production increases were realized in the Haro area with the drilling of 12 gas wells (7.5 net), and the completion of the expansion in June of the existing natural gas production capacity from 1.4 MMcf/d to 5.9 MMcf/d. This increase was offset by declines at Cameron Hills and Bistcho.

The planned focus of activity in Northwest Alberta in 2005 will be in the Bistcho-Zama-Larne area with potential participation in the drilling of 19 gross (9.5 net), operated and non-operated gas wells. In the Haro area, 6 (4 net) gas wells are expected to be drilled. The Company also plans to conduct two seismic programs on new lands acquired in 2004. Activity in Cameron Hills, Northwest Territories, will be limited as regulatory approvals for new drilling has not been received.

NORTHWEST TERRITORIES / NORTHEAST BRITISH COLUMBIA

Production from this operating area increased from 12 MMcf/d in 2003 to 16 MMcf/d in 2004. The increase was a result of both drilling activity and the acquisition of additional working interests in three of the four producing properties. A total of 18 (9.4 net) wells were drilled during 2004, and two separate property transactions were closed during the year.

Development activity was focused on the West Liard field with the drilling of 3K-29 and 2M-25 along with a workover on the shut-in well at M-25. Both 2M-25 and M-25 were brought on production during the fourth quarter. Paramount's working interest in this field increased from 3 percent to 67 percent as a result of the 2004 acquisitions. Also included in the asset acquisitions was the remaining 50 percent interest in the Tattoo and Maxhamish production facilities.

Exploratory drilling continued at Colville Lake, Northwest Territories, where three wells were drilled with encouraging results. Two of these wells at K-14 and C-34 tested potential new pools while the third well at B-23 was

drilled to delineate the Nogha discovery. Paramount will continue its exploration efforts in the Colville Lake area with the drilling of five wells this winter and further completion and testing of existing wells.

Delineation and tie in of new discoveries in Northeast British Columbia should add between 2-5 MMcf/d in the first quarter of 2005. Six wells were also drilled on various exploratory prospects in Northeast British Columbia with two of these encountering potential new pools that require further delineation, while a third discovery is slated to be on production in 2005. The upcoming winter program will include drilling and workover activity to maximize value from the higher working interests in the existing production facilities.

SOUTHERN

The Southern Operating Unit encompasses three different regulatory jurisdictions, southern Alberta, northern Montana and the southwest of North Dakota.

The Company drilled 82 (40.8 net) wells in 2004 as compared to 20 (14.6 net) wells in 2003. The average production for the year was 11 MMcf/d of gas, with 1,798 Bbl/d of oil and natural gas liquids as compared to 10 MMcf/d of gas and 2,457 Bbl/d of oil and natural gas liquids in 2003. In the fourth quarter of 2004, the Southern Operating Unit produced 11 MMcf/d of gas, and 1,600 Bbl/d of oil and natural gas liquids. This was the most active quarter with 52 (21.8 net) wells drilled. Most of the activity was in the Chain region where 18 (14.6 net) Coalbed Methane ("CBM") wells and 5 (4.0 net) Belly River wells were drilled.

In the third quarter of 2004, Paramount divested all its operated properties in southeast Saskatchewan (for a gain of $14 million) to further focus the operations in the Southern Operating Unit core areas. The primary core areas of production are the gas-producing Chain/Craigmyle field and the oil-producing area of the Williston Basin in the United States.

The Chain region has seen a revival over the last two years and has doubled production from 3 MMcf/d to 6.2 MMcf/d. The 18 CBM wells were all successful and will form the base for a multi-year development program of the Horseshoe Canyon CBM play. These wells are drilled to a depth of 350 meters and produce natural gas at average rates of over 100 Mcf/d with no associated water production. The continuing Belly River drilling program has been very successful and has enabled existing infrastructure to operate at capacity. A re-evaluation of our facilities has shown the need for a new parallel low pressure production system on which we will start construction in the second quarter of 2005. The Chain region will be the focus of most of our activity in 2005 with 98 wells planned which consist of 88 CBM wells, eight wells for Belly River targets and two for Mannville targets.

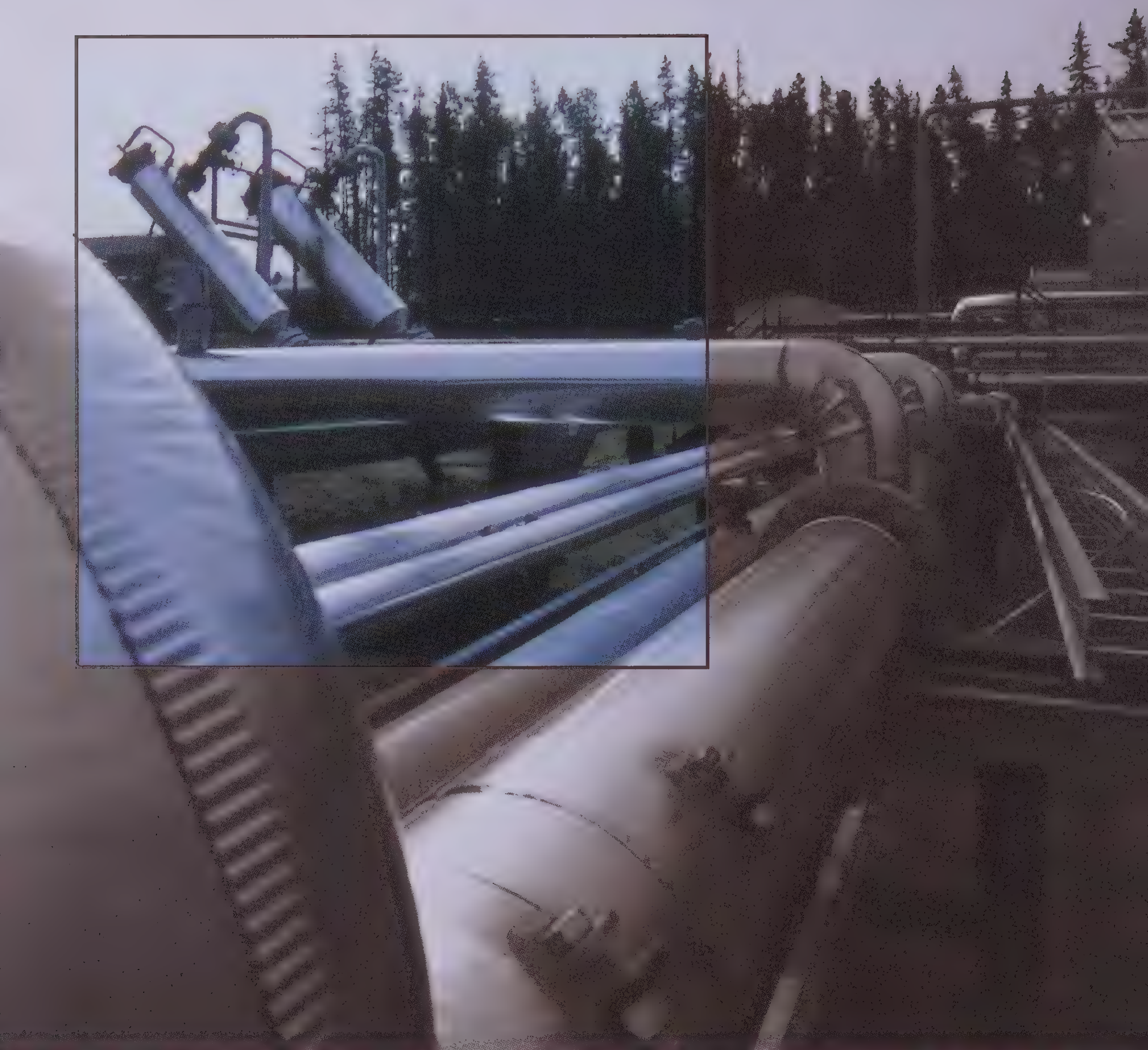
The North Dakota area is presently producing 564 Boe/d and will be the second area of focus for the Southern Operating Unit. Paramount will be drilling six wells for deep oil in the Knutson and Beavercreek Fields.

HEAVY OIL

During 2004 Paramount Resources increased its oil sands acreage by 70 percent with the acquisition of 51,000 acres of oil sands rights for a total cost of $2.7 million. The Company's total oil sands acreage is approximately 120,000 acres and is located mainly in the Leismer and Surmont areas of northeast Alberta. During 2004 Paramount drilled 17 Oil Sands Evaluation (OSE) wells. The encouraging results of these wells are being followed-up with a 15 to 20 well OSE program in early 2005. The Company is optimistic that the results of the oil sands evaluation program will allow it to bring forward a 3,000 Bbl/d SAGD pilot application in 2005.

GAS RE-INJECTION AND PRODUCTION EXPERIMENT

Paramount made a significant step towards a technical solution to the Gas over Bitumen issue with the approval of the Gas Re-Injection and Production Experiment to be conducted in the Surmont area of northeast Alberta. This pilot project involves the collection and re-injection of up to 3 MMcf/d of compressor exhaust gases, maintaining pressure, allowing a similar volume of natural gas production from previously shut-in gas pools. The experiment also enables the sequestration of up to 400 Mcf/d of carbon dioxide. This experimental pilot project is expected to start up in the second quarter of 2005. If successful, Paramount is hopeful that this experiment will offer some resolution at Surmont to the Gas over Bitumen issue as well as provide for sequestration opportunities for carbon dioxide.



REVIEW of OPERATIONS

PRODUCTION

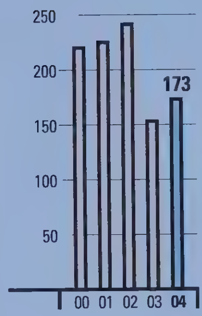
Paramount's production profile continued to be significantly weighted to natural gas. Natural gas production made up 80 percent of the Company's total production in 2004 compared to 78 percent in 2003.

Paramount's production for the year ended December 31, 2004 was 36,150 Boe/d, up 11 percent from 32,630 Boe/d in 2003. Natural gas production increased 13 percent from 152.8 MMcf/d in 2003 to 173.1 MMcf/d in 2004. Crude oil and natural gas liquids production increased 2 percent from 7,169 Bbl/d in 2003 to 7,297 Bbl/d in 2004. This increase in production is attributable to the 2004 acquisitions in the Kaybob, Fort Liard and Marten Creek areas and a successful capital program.

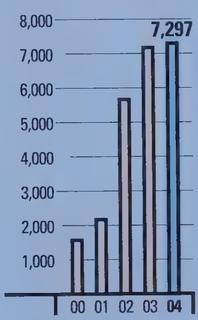
The following table summarizes the average daily production per core area.

Natural Gas Production (MMcf/d)	2004	2003
East Kaybob	89.7	77.6
Marten Creek	8.6	-
Total Trust Properties	98.3	77.6
West Kaybob	6.7	1.9
Grande Prairie (excluding Marten Creek)	18.2	12.4
Northwest Alberta / Cameron Hills, Northwest Territories	20.2	22.3
Northwest Territories / Northeast British Columbia	16.2	11.6
Southern	10.8	9.5
Other	2.7	17.5
Total Paramount (excluding Trust Properties)	74.8	75.2
Total Paramount	173.1	152.8
Crude Oil & NGL Production (Bbl/d)		
East Kaybob	3,874	2,184
Marten Creek	-	-
Total Trust Properties	3,874	2,184
West Kaybob	217	267
Grande Prairie (excluding Marten Creek)	585	1,767
Northwest Alberta / Cameron Hills, Northwest Territories	797	448
Northwest Territories / Northeast British Columbia	12	9
Southern	1,798	2,457
Other	14	37
Total Paramount (excluding Trust Properties)	3,423	4,985
Total Paramount	7,297	7,169
Total Production (Boe/d)		
East Kaybob	18,817	15,112
Marten Creek	1,432	-
Total Trust Properties	20,249	15,112
West Kaybob	1,340	592
Grande Prairie (excluding Marten Creek)	3,621	3,831
Northwest Alberta / Cameron Hills, Northwest Territories	4,165	4,165
Northwest Territories / Northeast British Columbia	2,710	1,942
Southern	3,596	4,048
Other	469	2,940
Total Paramount (excluding Trust Properties)	15,901	17,518
Total Paramount	36,150	32,630

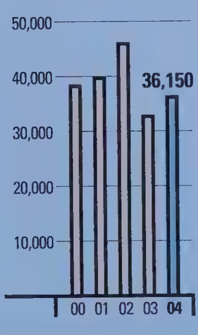
NATURAL GAS SALES (MMcf/d)



CRUDE OIL and LIQUIDS SALES (Bbl/d)



PRODUCTION (Boe/d @ 6:1)



PROFITABILITY

Paramount continues to focus its efforts on the control of factors directly related to profitability. Production volumes, operating costs, general and administrative costs, and capital spending are all factors that are within our control and remain closely monitored. The mandate of every employee is to turn ideas into value. This strategy has resulted in a history of increased shareholder value.

COMMODITY PRICES

Stronger natural gas demand resulted in an increase of 12 percent in Paramount's average natural gas sales price before financial instruments to $6.72/Mcf as compared to $5.99/Mcf in 2003. Natural gas prices after financial instruments in 2004 increased 33 percent to $6.86/Mcf from $5.16/Mcf in 2003. In 2004, Paramount recorded a $18.7 million gain on financial instruments as compared to a loss of $53.2 million in 2003. The 2003 financial instruments were initiated in order to reduce cash flow risk with respect to the Summit acquisition as the bridge loan used to finance the acquisition was extended due to unexpected delays in closing the Paramount Energy Trust disposition. Oil and natural gas liquids ("NGL") prices before financial instruments increased 22 percent to average $46.80/Bbl in 2004, as compared to $38.27/Bbl in 2003.

OPERATING COSTS

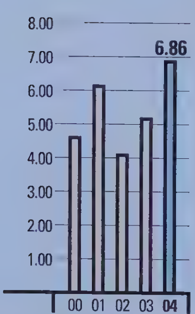
Paramount's total operating costs increased 18 percent to $95.8 million in 2004 as compared to $81.2 million in 2003. Costs on a unit-of-production basis increased 6 percent to $7.24/Boe from $6.82/Boe in 2003. The industry in general experienced increases in the costs of goods and services particularly higher labour and energy costs. In addition, properties acquired by the Company during the year have higher per unit operating costs than existing Paramount properties. Paramount constructs and operates plant facilities and gathering systems as a corporate strategy in order to control the flow of its natural gas to market. These facilities incur fixed costs, which are in addition to the costs incurred at the well level, thereby increasing total operating expenses and the relative magnitude of the per unit costs.

ROYALTIES

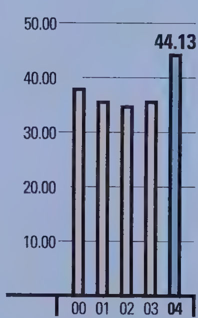
For 2004, net royalties increased to $105.0 million from $82.5 million in 2003 due to higher production and commodity prices. As a percentage of revenue, Paramount's corporate royalty rate is substantially unchanged from the prior year, at 19.1 percent compared to 19.0 percent in 2003.

GENERAL AND ADMINISTRATIVE COSTS

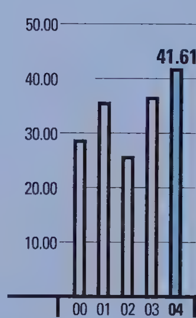
General and administrative expenses, net of operating recoveries, increased to $25.2 million in 2004 as compared to $19.1 million in 2003. Paramount has increased its head-office staffing levels to enable the Company to identify and develop new core areas and build its production portfolio. This initiative has resulted in Paramount advancing its long-term projects such as Colville Lake, Northeast Alberta bitumen and Coalbed Methane, and developing



NATURAL GAS PRICE
(after realized financial instruments)
($/Mcf)



CRUDE OIL and LIQUIDS PRICE
(after realized financial instruments)
($/Bbl)



GROSS REVENUE
(before financial instruments)
($/Boe)

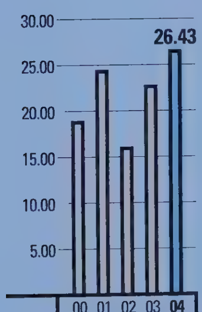
successful new fields in existing core areas within Grande Prairie and Northwest Alberta. The Company has also increased administrative staff levels to ensure compliance with new corporate and reporting obligations in Canada and the United States; certain of these are a result of the US debt offerings closed in 2004. Paramount does not capitalize any general and administrative expenses with the exception of overhead recoveries.

CASH FLOW AND EARNINGS

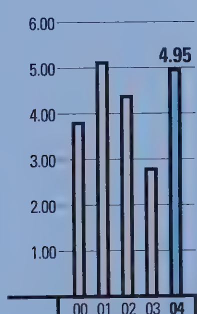
Paramount's cash flow from operations increased 77 percent to $295.6 million in 2004 from $167.3 million in 2003. The increase in cash flow was a result of a reduction in realized financial instrument losses in 2004 as compared to 2003, and an increase in revenues due to higher commodity prices and production. Net earnings totaled $41.2 million as compared to net earnings of $1.2 million in 2003. The higher earnings in 2004 are primarily due to an increase in petroleum and natural gas sales resulting from higher production and commodity prices, financial instrument gains as opposed to 2003 losses, and unrealized foreign exchange gains on US debt. This was partially offset by higher non-cash stock based compensation expense, depletion and depreciation expense, and future income tax expense.

Cash Flow Reconciliation	**2004**		2003	
Volume (Boe) (1)	($ million)	$/Boe	($ million)	$/Boe
Petroleum & natural gas revenue, net of transportation	**550.6**	**41.61**	434.1	36.45
Gain (loss) on sale of investments	**-**	**-**	(1.0)	(0.09)
Royalties (net of ARTC)	**(105.1)**	**(7.94)**	(82.5)	(6.93)
Operating costs	**(95.8)**	**(7.24)**	(81.2)	(6.82)
Operating netback	**349.7**	**26.43**	269.4	22.61
Realized financial instruments	**(0.7)**	**(0.05)**	(53.2)	(4.47)
Interest on long-term debt (excluding non-cash interest)	**(24.1)**	**(1.82)**	(19.0)	(1.60)
General and administrative	**(25.2)**	**(1.91)**	(19.1)	(1.60)
Bad debt recovery (expense)	**5.5**	**0.42**	(6.0)	(0.50)
Lease rentals	**(3.5)**	**(0.27)**	(3.6)	(0.30)
Current and Large Corporations Tax	**(6.8)**	**(0.51)**	(2.7)	(0.23)
Cash flow from continuing operations	**294.9**	**22.29**	165.8	13.91
Cash flow from discontinued operations	**0.7**	**0.05**	1.5	0.13
Cash flow from operations	**295.6**	**22.34**	167.3	14.04
Weighted average shares (millions)	**59.8**	**60.1**		
Cash flow per basic share ($/share)	**4.95**	**2.78**		

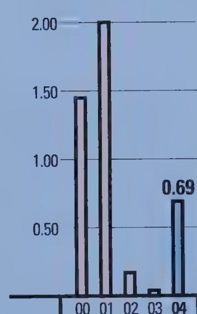
(1) Barrels of oil equivalent calculated on the basis of 1 barrel = 6 Mcf.



OPERATING NETBACK
($/Boe)



CASH FLOW PER SHARE
($/share, basic)



EARNINGS PER SHARE
($/share, basic)

NET CAPITAL EXPENDITURES

During 2004, expenditures for exploration and development activities totaled $316.3 million as compared to $223.8 million in 2003. The increase in the capital expenditures program in 2004 resulted in a total of 271 gross (180 net) wells were drilled during the year, compared to 211 gross (139 net) wells in 2003.

Net capital expenditures totaled of $579.0 million in 2004 as compared to a recovery of $145 million in 2003. The Company acquired a number of properties totaling $322.6 million in 2004 offset by the disposition of certain non-core properties.

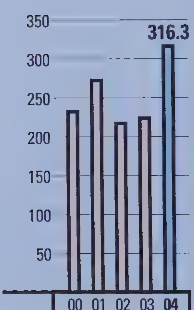
Capital Expenditures ($millions)		**2004**		2003
Land	**$**	**37.9**	$	22.3
Geological and geophysical		**8.7**		8.4
Drilling		**184.5**		123.5
Production equipment and facilities		**85.2**		69.6
Exploration and development expenditures		**316.3**		223.8
Property acquisitions		**322.6**		0.9
Proceeds received on property dispositions		**(61.8)**		(371.6)
Other		**1.9**		1.9
Net capital expenditures	**$**	**579.0**	$	(145.0)

LAND

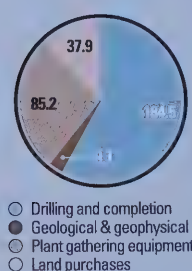
The Company's net land holdings increased 20 percent to 4,082 thousand acres from 3,386 thousand acres in 2003. Net undeveloped lands increased 23 percent to 3,442 thousand acres from 2,800 thousand acres in 2003. Paramount's undeveloped land inventory was increased partially as a result of acquisition and as a result of $37.9 million spent at Crown land sales.

The following table summarizes the Company's acreage position at December 31, 2004:

Land (thousand acres)	**2004**			2003		
	Gross	**Net**	**Average Working Interest**	Gross	Net	Average Working Interest
Land assigned reserves	**1,098**	**640**	**58%**	981	586	60%
Undeveloped land	**5,536**	**3,442**	**62%**	4,756	2,800	59%
Total	**6,634**	**4,082**	**62%**	5,737	3,386	
Fair market value of undeveloped land ($millions)	**$ 185.4**			$ 98.20		



EXPLORATION and DEVELOPMENT EXPENDITURES
($ millions)



2004 EXPLORATION and DEVELOPMENT EXPENDITURES
($ millions)

DRILLING

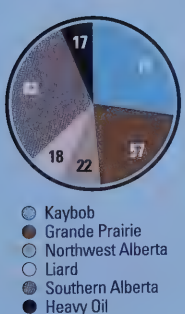
Paramount participated in the drilling of 271 (180.3 net) wells in 2004 with a success rate of 96 percent. A total of 229 (145.6 net) gas wells, 12 (9.5 net) oil wells, 17 (17.0 net) heavy oil wells and 13 (8.2 net) dry and abandoned wells were drilled. The highest number of net drills was in the Kaybob Operating Unit, 75 (52.2 net) wells drilled. Grande Prairie Drilled 57 (46.4 net) wells, Northwest Alberta drilled 22, (14.5 Net) wells, Liard drilled 18 (9.4 net) wells and Southern Alberta drilled 82 (40.8 net) wells. The Company also drilled 17 (17.0 net) heavy oil evaluation wells in northeast Alberta.

The following table summarizes the Company's 2004 drilling results:

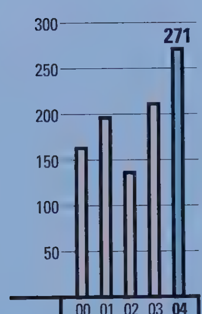
	2004				2003			
	Development		Exploration		Development		Exploration	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Gas	164	102.8	65	42.8	135	90.0	45	30.7
Oil	11	8.6	1	0.9	13	10.4	3	2.1
D&A	9	4.9	4	3.3	7	3.5	8	2.2
Heavy Oil	17	17.0	-	-				
Total	201	133.3	70	47.0	155	103.9	56	35.0
Total All Wells	271	180.3			211	138.9		
Success	95%				93%			

RESERVES AND RESERVES REPLACEMENTS

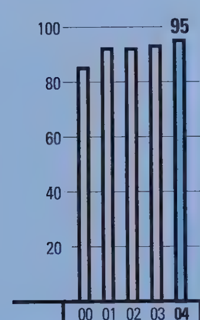
Paramount's reserves for the year ended December 31, 2004, were evaluated by McDaniel and Associates Consultants Ltd. ("McDaniel") and by Paddock Lindstrom and Associates Ltd. ("Paddock Lindstrom"). Paramount's reserves have been calculated in compliance with the national Instrument 51-101. Natural gas reserves for the year ended 2004 were 568.6 Bcf as compared to 329.4 Bcf for the year ended 2003. This represents a 73 percent increase in natural gas reserves. The crude oil and natural gas liquids reserves for the year ended 2004 were 20,461 MBbl, a 64 percent increase over the year end 2003 reported 12,513 MBbl. Crude oil reserves increased from 8,106 MBbl to 12,031 MBbl while natural gas liquids reserves increased from 4,407 MBbl to 8,430 MBbl.



DRILLING DISTRIBUTION



WELLS DRILLED (gross)



DRILLING SUCCESS RATE (%)

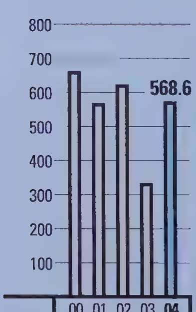
The following table summarizes the reserves evaluated as at December 31, 2004, using McDaniel's and Paddock's forecast prices and cost cases:

	Gross Proved and Probable Reserves				Before Tax Net Present Value ($millions)		
Reserve Category	Natural Gas	Light and medium Crude Oil	Natural Gas Liquids	Boe	Discount Rate		
	(Bcf)	(MBbl)	(MBbl)	(MBoe)	0%	5%	10%
Canada							
Proved							
Developed Producing	254.5	5,615	5,552	53,592	1,266.6	1,063.9	929.5
Developed Non-Producing	52.4	667	501	9,898	205.7	166.1	140.8
Undeveloped	39.9	308	289	7,251	142.8	91.2	64.0
Total Proved	346.9	6,590	6,342	70,741	1,615.2	1,321.2	1,134.3
Probable	221.3	2,901	2,087	41,882	950.6	663.5	500.7
Total Proved Plus Probable Canada	568.2	9,492	8,430	112,622	2,565.8	1,984.7	1,635.0
United States							
Proved							
Developed Producing	0.4	2,108	-	2,169	29.8	25.3	21.9
Developed Non-Producing	-	-	-	-	(0.4)	(0.3)	(0.3)
Undeveloped	-	-	-	-	-	-	-
Total Proved	0.4	2,108	-	2,169	29.5	25.0	21.6
Probable	-	431	-	437	6.0	3.9	2.7
Total Proved Plus Probable US	0.4	2,539	-	2,606	35.5	28.8	24.3
Total Proved	347.2	8,698	6,342	72,910	1,644.7	1,346.2	1,156.0
Total Probable	221.4	3,332	2,087	42,319	956.6	667.4	503.4
Total Reserves	568.6	12,031	8,430	115,230	2,601.3	2,013.6	1,659.3

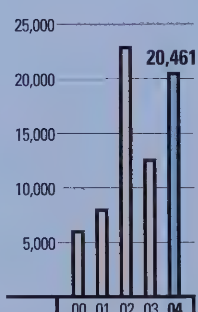
(Columns may not add due to rounding)

RESERVE RECONCILIATION FOR YEAR-END 2004

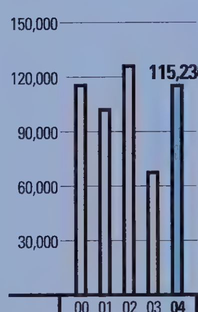
Total proved reserves at year end 2004 were approximately 347 Bcf and 15.0 MMBbl or 73 MMBoe and proved plus probable reserves were 569 Bcf and 20.5 MMBbl or 115.2 MMBoe. On a barrel equivalent basis, reserves increased approximately 71 percent or 48 MMBoe over year end 2003. This growth in reserves replaces 2004 production of 13 MBoe by over four times.



NATURAL GAS RESERVES
PROVED and PROBABLE (gross before royalties) (Bcf)



CRUDE OIL and NGL RESERVES
PROVED and PROBABLE (gross before royalties) (MBbl)



RESERVES
(MBoe)

The Company's new reserves and extensions to existing proved plus probable reserves totaled 27.9 MMBoe, acquisitions increased reserves by 26.1 MMBoe. Further development and additional production information enabled positive reserve revisions of 8.4 MMBoe. The Company's divestitures of certain non-core properties accounted for 1.2 MMBoe.

The following table sets forth the reconciliation of Paramount's gross reserves for the year ended December 31, 2004, as evaluated by McDaniel and Paddock Lindstrom using forecast prices and costs. Gross reserves include working interest reserves before royalties.

Reserves (Company share before royalty)

	Proved Reserves			Probable Reserves			Proved + Probable Reserves		
	Gas	Oil & NGL	Boe	Gas	Oil & NGL	Boe	Gas	Oil & NGL	Boe
	Bcf	MBbl	MBoe	Bcf	MBbl	MBoe	Bcf	MBbl	MBoe
Total Reserves Jan 1, 2004	241.7	10,617	50,900	87.7	1,896	16,513	329.4	12,513	67,413
Total 2004 Divestments(1)	(0.2)	(1,021)	(1,042)	-	(176)	(176)	(0.2)	(1,196)	(1,224)
Total 2004 acquisitions(1)	63.1	5,426	15,951	51.6	1,505	10,108	114.8	6,931	26,059
2004 Capital Program Additions(1)	83.3	1,624	15,510	64.9	1,532	12,346	148.2	3,156	27,856
Total 2004 Production	(63.4)	(2,671)	(13,231)	-	-	-	(63.4)	(2,671)	(13,231)
Technical Revisions(1)	22.6	1,066	4,830	17.2	662	3,525	39.8	1,727	8,355
Total Reserves Jan. 1, 2005	347.2	15,041	72,910	221.4	5,420	42,319	568.6	20,460	115,230

(Columns may not add due to rounding)
(1) Paramount estimates.

FINDING AND DEVELOPMENT COSTS

Paramount has calculated the capital associated with the 2004 reserve additions and as such has excluded certain capital expenditures. The calculation excluded the $37.6 million of expenditures from the finding and development cost calculation associated with the exploration at Colville Lake and the Bitumen evaluation. This capital will be included in the finding and development calculation during the year in which reserves are first booked for Colville Lake and Bitumen by the company. In addition, capital was reduced by $45.1 million to reflect the net increase in the value of our undeveloped acreage inventory. Future capital of $36.2 million to fully develop the booked proved reserves, and $103.2 million to fully develop the proved and probable reserves were included in the finding and development calculation. Paramount's finding and development costs for new reserves additions were calculated to be $13.57/Boe for proved reserves and $9.48/Boe for proved plus probable reserves.

Finding and Development Capital

2004 Working Interest Capital Expenditures		Future Capital New Additions		Total F&D Capital	
($ millions)	2004 Capital	Proved	Proved Plus Probable	Proved	Proved Plus Probable
Land	38.0	-	-	38.0	38.0
Seismic	8.9	-	-	8.9	8.9
Exploration and development	184.5	20.2	77.3	204.7	261.8
Facilities	91.4	16.0	25.9	107.4	117.3
Total net capital expenditures	322.8	36.2	103.2	359.0	426.0
Less increase in value of undeveloped land	(45.1)	-	-	(45.1)	(45.1)
Less 2004 Colville expenditures	(29.3)	-	-	(29.3)	(29.3)
Less 2004 Bitumen evaluation expenditures	(8.3)	-	-	(8.3)	(8.3)
2004 F&D net capital expenditures	**240.1**	**36.2**	**103.2**	**276.3**	**343.3**

	Proved Capital ($MM)	Proved Reserves (MBoe)	Proved F&D ($/Boe)	Proved Plus Probable Capital ($MM)	Proved Plus Probable Reserves (MBoe)	Proved Plus Probable F&D ($/Boe)
Finding and Development Costs						
Extensions and discoveries (including technical revisions)	276.3	20,360	13.57	343.3	36,231	9.48

ACQUISITION AND DIVESTMENT ACTIVITIES ("A&D")

In 2004, Paramount acquired properties in Alberta and the Northwest Territories with 15,951 MBoe of proved reserves, or 26,059 MBoe proved plus probable reserves as well as undeveloped land valued at $35.0 million, at a total cost of $322.6 million. Paramount also divested of non-core properties in Alberta and Saskatchewan with reserves of 1,042 MBoe proved, or 1,224 MBoe proved plus probable reserves as well as undeveloped land valued at $1.0 million, for total divestment proceeds of $52.1 million. In aggregate, Paramount increased total proved reserves by 14,909 MBoe for a net unit cost of $15.86/Boe, and increased proved plus probable reserves by 24,835 MBoe for a net unit cost of $9.52/Boe through acquisition and divestment activity.

2004 Working Interest Capital Expenditures ($ millions)	
Capital Expenditures for Acquisitions	322.6
Fair Market Value of Undeveloped Land Acquired	(35.0)
Proceeds of Dispositions of P&NG assets	(52.1)
Fair Market Value of Undeveloped Land Divested	1.0
Net A&D Capital for Reserves	**236.5**

	Proved Capital ($MM)	Proved Reserves (MBoe)	Proved A&D ($/Boe)	Proved Plus Probable Capital ($MM)	Proved Plus Probable Reserves (MBoe)	Proved Plus Probable A&D ($/Boe)
Net 2004 A&D Expenditures	270.5			270.5		
Less: Net Value of A&D Undeveloped Land	34.0			34.0		
2004 Net A&D Cost of Reserves	**236.5**	**14,909**	**15.86**	**236.5**	**24,835**	**9.52**

TOTAL RESERVE GROWTH COST (F&D Cost plus Acquisitions and Divestments)

Paramount's 2004 F&D related activities, when combined with its acquisition and divestment program resulted in total reserve growth of 35,269 MBoe total proved reserves ($14.53/Boe unit cost) and 61,066 MBoe of proved plus probable reserves ($9.49/Boe unit cost).

Total Reserve Growth (F&D + A&D)	**512.8**	**35,269**	**14.53**	**579.8**	**61,066**	**9.49**

NET ASSET VALUE

The net asset value of Paramount at year end has increased 141 percent from $10.38 in 2003 to $25.01 in 2004. One of the main components of the increase was the 126 percent increase in value of reserves and the 89 percent increase in the appraised value of undeveloped land.

The following table summarizes the Company's net asset value:

Net Asset Value ($ millions of dollars as at December 31, 2004)	**2004**	2003
Present value of appraised reserves (1)	**$ 1,659.3**	$ 733.6
Value of short-term investments	**27.1**	17.3
Appraised value of undeveloped land	**185.4**	98.2
Seismic (at cost)	**55.4**	37.6
Projects under evaluation (at cost)	**117.8**	42.1
Building (at cost)	**-**	8.5
Other	**11.3**	10.6
Total assets	**2,056.3**	947.9
Bank loans	**201.3**	60.4
Senior notes	**257.8**	226.9
Working capital deficiency (2)	**17.0**	25.7
Drilling rig indebtedness	**-**	4.6
Mortgage	**-**	6.7
Total liabilities	**476.1**	324.3
Net asset value	**$ 1,580.2**	$ 623.6
Net asset value per basic common share (3)	**$ 25.01**	$ 10.38

(1) Proved plus probable reserves discounted at 10 percent before income tax used for 2004.
(2) Excludes short-term investments.
(3) Outstanding shares: 2004 – 63,185,600 (2003: 60,094,600).

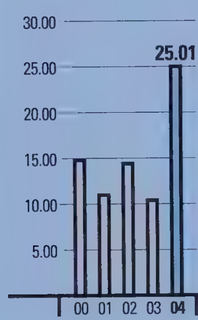
NOTES TO NET ASSET VALUE

i) Reserve values were determined by McDaniel and Paddock Lindstrom as at December 31, 2004, using their forecast prices and costs cases.

ii) No value has been assigned to tangible assets other than those associated with proved producing reserves.

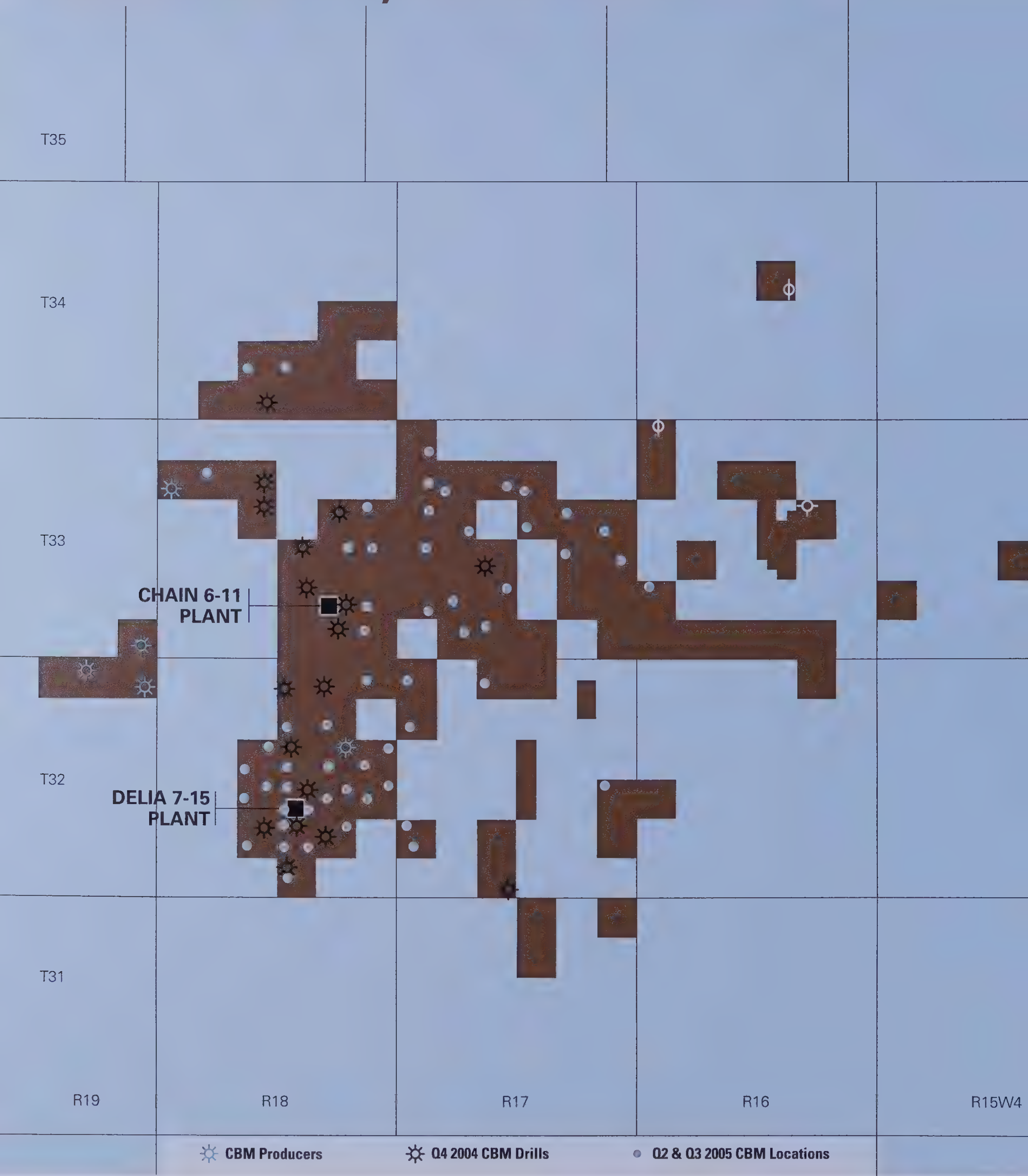
iii) Paramount's hedging activities, which extend past December 31, 2004, have not been valued by McDaniel or Paddock Lindstrom.

iv) Reserve values have been evaluated under a blow-down scenario.



NET ASSET VALUE
($/share)

Coalbed Methane, *southern Alberta*



AREAS of INTEREST

COALBED METHANE

Coalbed Methane (CBM) or natural gas from Coal (NGC) is an 'unconventional' source of natural gas. In southern Alberta the Horseshoe Canyon coals of the Edmonton group has become one of the hottest land and drilling plays on the continent. Historically, CBM has been produced from wet coal seams, where huge amounts of water are removed to allow natural gas to desorb and produce from the coal. This is the case in the San Juan, Powder River and Black Warrior basins in the United States. In Southern Alberta however, the Horseshoe Canyon coals do not contain water, they are dry, and therefore the natural gas produces from the coal seams immediately after stimulation with no appreciable water production. The rates and reserves from these wells are similar to that from the Medicine Hat and Milk River formation wells which have been the mainstay of Alberta production for the last century. These wells typically produce at steady rates of natural gas with minimum declines and have a long reserve life.

The producing region for the Horseshoe Canyon stretches along the central part of Alberta from Calgary to just south of Edmonton. Paramount's land holdings in Chain/Craigmyle are located on the eastern edge of this fairway. In 2004 Paramount participated in 20 wells and completions targeting the Horseshoe Canyon coals. The wells produce gas from the zone at depths between 80 and 350 meters with rates of over 100 Mcf/d.

Paramount will be drilling 88 wells in 2005 for CBM in what is the second year of a multi-year exploration and development program. Paramount will be drilling up to 4 wells per section depending on drainage and reserves from each well, and have applied to the Alberta Energy and Utility Board for reduced drill spacing to achieve this in 2005.

As part of this program, we are also building a production system which will utilize large diameter pipelines and centrally located compressors to maximize deliverability and reserve recovery of the gas field and reduce the proliferation of multiple small wellhead compressors. This is in keeping with the production philosophy we pioneered 26 years ago producing shallow gas in northeast Alberta. With a streamlined production system such as this, though up front costs may be higher, long term operating costs and environmental impact are kept to a minimum. This is an area which has seen oil and gas development in a variety of different plays for the last 60 years, as well as constituting the main agricultural region of Alberta. Paramount is well aware of the responsibility of operating in such an area, and is working with the surface land owners to achieve seamless operations to the benefit of all.

Colville Lake, *Northwest Territories*

AREAS of INTEREST

COLVILLE LAKE

The Colville Lake development is situated at the Arctic Circle, 1850 kilometres north of Calgary, within the Sahtu settlement region in the Northwest Territories. The area was recognized by Paramount as having significant potential for large scale hydrocarbon reserves within the Cambrian-aged Mount Clark and overlying Mount Cap sandstones. Previous National Energy Board (NEB) Significant Discovery Licenses recognize over 400 Bcf in the area. In 2004 Paramount and its 50 percent partner, Apache Canada, increased our already significant land position in the Sahtu, to over 940,000 acres (over 40 Alberta townships) in three distinct areas; the Nogha gas discovery, Maunoir Ridge, and Turton Lake.

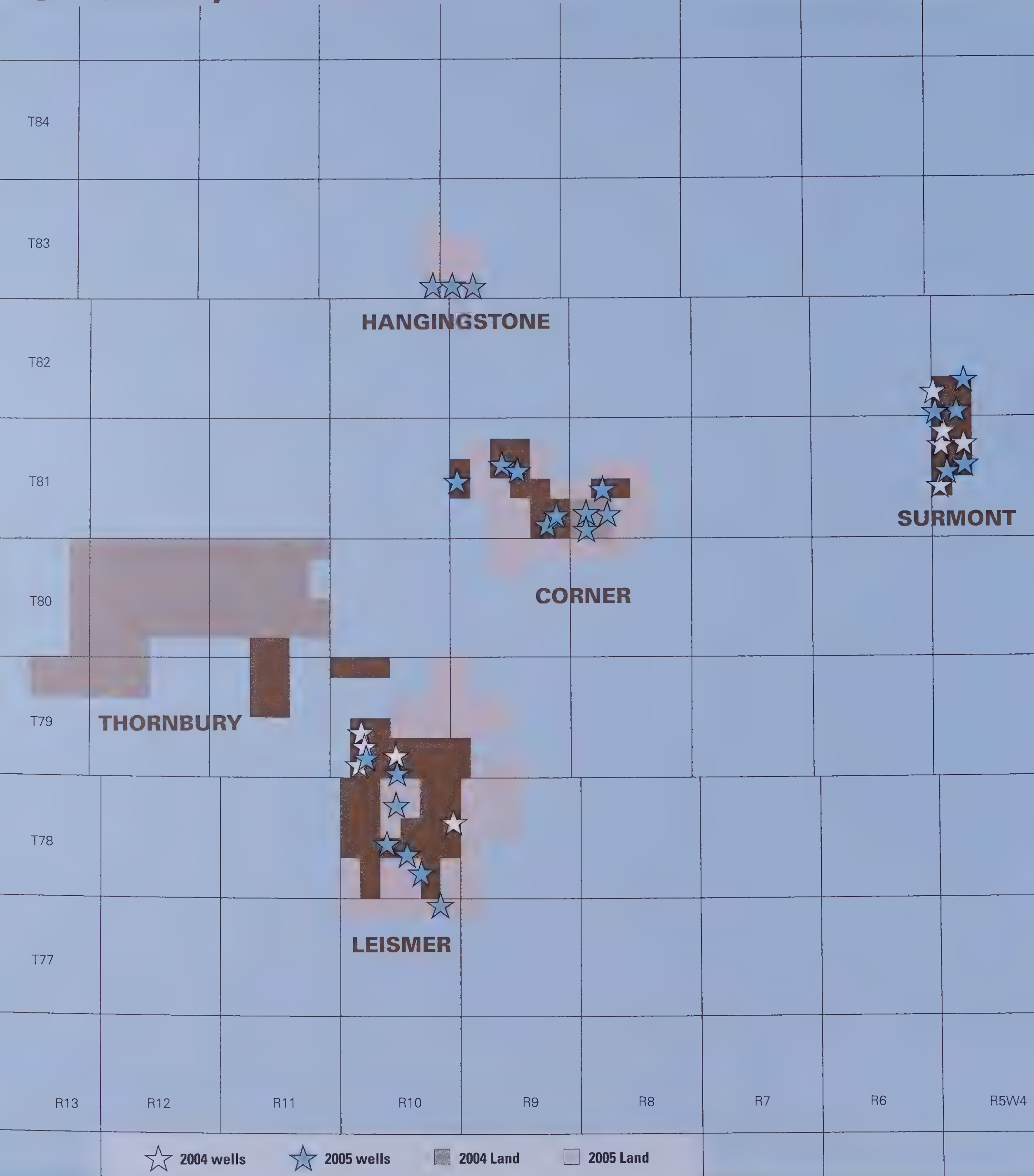
In 2003, Paramount and Apache drilled and cased two wells in the Nogha prospect, the Nogha C-49 discovery well and Nogha M-17 down structure. These wells were cased and tested, flowing at between 3 and 5 MMcf/d. In 2004 wells K-14 and B-23 were drilled and cased, further delineating the discovery. McDaniel and Associates have independently reviewed the Nogha exploration results and assigned possible raw gas reserves of 250 Bcf to a 17,000 acre area defined by the C-49 and M-17 wells. During the 2005 winter season Paramount and Apache will re-complete K-14 and B-23 to confirm well deliverability.

In 2004, Paramount and Apache drilled and cased Maunoir C-34 as part of the federal exploration commitments on Exploration License (EL) 399. During the 2005 winter drilling season we will drill three additional wells at Maunoir A-67, E-35 and L-80. Successful drilling at Maunoir would significantly improve the economic viability of development in the Sahtu.

Paramount and Apache will also drill the G-47 well at Turton Lake (on EL 414) to validate the Federal Exploration license acquired in 2003.

In late 2004 Imperial Oil Resources Ventures Limited filed application with the NEB to construct the Mackenzie Valley Pipeline (MVPL). If approved and completed on schedule, the pipeline would start up in 2009, delivering gas from the Mackenzie Delta and Valley to the existing pipeline infrastructure in northern Alberta. Several gathering and development scenarios are being considered to deliver Colville gas to the MVPL, and upon successful completion of this year's program. Paramount will commence conceptual development planning. Paramount's goal is to complete the area's initial development in time to make gas deliveries at MVPL start-up.

Oil Sands, *northeast Alberta*



STEAM ASSISTED GRAVITY DRAINAGE (SAGD) OIL SANDS

The Alberta Oil Sands are the largest single deposit of hydrocarbons in the world. The recoverable heavy oil from Alberta's Oil Sands is second only to Saudi Arabia in terms of total proven crude oil reserves. Alberta's Oil Sands underlie 140,800 square kilometers, an area larger than the state of Florida.

Paramount Resources holds 120,000 acres of oil sands rights in the Athabasca Oil Sands area. The recoverable heavy oil, also called bitumen, is located in the Lower Cretaceous McMurray sands of the Manville group.

During 2004 Paramount Resources increased our oil sands holdings by 70 percent, acquiring 51,000 acres of oil sands rights. Paramount now holds over 180 sections of oil sands centered in the areas of Surmont and Leismer of northeast Alberta. In 2004 Paramount drilled 10 Oil Sands Evaluation (OSE) wells to identify bitumen in place. An aggressive OSE program in 2005 is expected to lead to a SAGD prototype facility application in late 2005.

Paramount will recover bitumen using Steam Assisted Gravity Drainage – also know as "SAGD". In SAGD two parallel 800 meter horizontal wells are drilled in at the bottom of the reservoir, one 5 meters higher than the other. About 2000 Bbl/d of steam is injected in the upper well, the bitumen is heated, and then drains by gravity into the lower well at rates of about 750 Bbl/d.

Conventional SAGD plants burn natural gas to generate the steam used to recover bitumen. Paramount Resources is committed to develop fuels other than natural gas for use in its commercial oil sands plants. Paramount is conducting an alternate fuel research and development program in 2005 to commercialize another fuel, which could significantly lower our long term cost of bitumen recovery.

Paramount's development prospects are in four distinct areas. At Leismer Paramount holds 37 sections estimated to hold over a billion barrels of bitumen in place. In 2005 Paramount will drill about 15 wells in Leismer to identify an initial commercial development area. Upon confirmation of commercial potential, Paramount will commence the design and regulatory process necessary to start-up a 3,000 Bbl/d prototype project in 2006. The successful demonstration project could lead to a 30,000 Bbl/d commercial project for start-up as early as 2008 or 2009.

At Surmont Paramount has 11 sections of land directly offsetting the Surmont Commercial Project. In 2005 Paramount will continue OSE drilling and complete a conceptual design, leading to development of a commercial recovery scheme following Leismer.

At Corner and Thornbury, Paramount holds additional potential resources which position the Company with heavy oil opportunities which extend through 2025.

MANAGEMENT'S DISCUSSION and ANALYSIS ("MD&A")

Paramount Resources Ltd. ("Paramount" or the "Company") is pleased to report its financial and operating results for the year ended December 31, 2004.

The following discussion of financial position and results of operations should be read in conjunction with the consolidated financial statements and related notes for the year ended December 31, 2004. The consolidated financial statements have been prepared in Canadian dollars and in accordance with Canadian generally accepted accounting principles ("GAAP"). A reconciliation to United States GAAP is included in Note 17 to the consolidated financial statements.

This MD&A contains forward-looking statements within the meaning of applicable securities laws. Forward-looking statements include estimates, plans, expectations, opinions, forecasts, projections, guidance or other statements that are not statements of fact. The forward-looking statements in this MD&A include statements with respect to, among other things: Paramount's business strategy, Paramount's intent to control marketing and transportation activities, the weighting of Paramount's production toward natural gas, reserve estimates, production estimates, financial instrument policies, asset retirement obligations, the size of available income tax pools, the renewal of the Company's credit facility, the funding sources for the Company's capital expenditure program, cash flow estimates, environmental risks faced by the Company and compliance with environmental regulations, commodity prices, and the impact of the adoption of various Canadian Institute of Chartered Accountants Handbook Sections and Accounting Guidelines.

Although Paramount believes that the expectations reflected in such forward-looking statements are reasonable, undue reliance should not be placed on them because the Company can give no assurance that such expectations will prove to have been correct. There are many factors that could cause forward-looking statements not to be correct, including known and unknown risks and uncertainties inherent in the Company's business. These risks include, but are not limited to: crude oil and natural gas price volatility, exchange rate and interest rate fluctuations, availability of services and supplies, market competition, uncertainties in the estimates of reserves, the timing of development expenditures, production levels and the timing of achieving such levels, the Company's ability to replace and expand oil and gas reserves, the sources and adequacy of funding for capital investments, future growth prospects and current and expected financial requirements of the Company, the cost of future asset retirement obligations, the Company's ability to enter into or renew leases, the Company's ability to secure adequate product transportation, changes in environmental and other regulations, the Company's ability to extend its debt on an ongoing basis, and general economic conditions. The Company's forward-looking statements are expressly qualified in their entirety by this cautionary statement. We undertake no obligation to update our forward-looking statements except as required by law.

Included in this MD&A are references to financial measures such as cash flow from operations ("cash flow") and cash flow per share. While widely used in the oil and gas industry, these financial measures have no standardized meaning and are not defined by Canadian generally accepted accounting principles ("GAAP"). Consequently, these are referred to as non-GAAP financial measures. Cash flow appears as a separate caption on the Company's consolidated statement of cash flows and is reconciled to net earnings. Paramount considers cash flow a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future growth through capital investment and to repay debt. Cash flow should not be considered an alternative to, or more meaningful than, net earnings as determined in accordance with GAAP, as an indicator of the Company's performance.

In this MD&A, certain natural gas volumes have been converted to barrels of oil equivalent (Boe) on the basis of six thousand cubic feet (Mcf) to one barrel (Bbl). Boe may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf=1 Bbl is based on an energy equivalency conversion method, primarily applicable at the burner tip and does not represent equivalency at the well head.

Early in 2003, the Company disposed of a significant number of assets to Paramount Energy Trust. The net book value of the assets amounted to $244.4 million (17 percent) of total assets as of December 31, 2002, 94.8 Mcf/d (39 percent) of total natural gas production, and 15,807 Boe/d (34 percent) of total production. As such, the 2002

comparative figures shown in this MD&A report contains the results of these assets and should be read and interpreted with this understanding.

As of March 8, 2005 Paramount had 63.9 million common shares outstanding.

The date of this MD&A is March 9, 2005.

Additional information on the Company, including the Annual Information Form, can be found on the SEDAR website at www.sedar.com.

Paramount Resources Ltd. (Paramount" or the "Company") is an independent Canadian energy company involved in the exploration, development, production, processing, transportation and marketing of natural gas and oil. The Company's principal properties are located in Alberta, the Northwest Territories and British Columbia in Canada. The Company also has properties in Saskatchewan and offshore the East Coast in Canada, and in Montana and North Dakota in the United States. Management's strategy is to maintain a balanced portfolio of opportunities, to grow reserves and production in the Company's core areas while maintaining a large inventory of undeveloped acreage, to focus on natural gas as a commodity, and to selectively enter into joint venture agreements for high risk/high return prospects.

SIGNIFICANT EVENTS

REORGANIZATION

On December 13, 2004 Paramount announced that its Board of Directors had unanimously approved a proposed reorganization which would result in Paramount's shareholders receiving units of a new energy trust (the "Trust", now named Trilogy Energy Trust) which will indirectly own existing properties of Paramount with current production of approximately 25,000 Boe/d (the "Trust Spinout"). Under the Trust Spinout, Paramount's shareholders will continue to be shareholders of Paramount, which will continue to operate as it has in the past.

The Company has also announced that a special meeting of security holders to consider its previously announced trust spinout transaction is scheduled to be held on Monday, March 28, 2005. The Trust Spinout is expected to be effected through an arrangement under the Business Corporations Act (Alberta). The transaction is subject to approval by the shareholders and option holders of Paramount, the Court of Queen's Bench of Alberta and regulatory authorities.

At the meeting, holders of Paramount common shares and options will be asked to approve the Trust Spinout which would result in Paramount shareholders receiving units of a new energy trust, to be known as Trilogy Energy Trust ("Trilogy"). Upon completion of the Trust Spinout, Paramount shareholders will own 100 percent of post-reorganization Paramount and 81 percent of the outstanding units of Trilogy. Paramount will own the remaining 19 percent of the outstanding units of Trilogy. Shareholders will receive one trust unit for each existing common share. Based on the number of Paramount shares outstanding on February 25, 2005, there are expected to be approximately 63.9 million common shares of Paramount and 78.9 million units of Trilogy outstanding upon completion of the Trust Spinout.

Trilogy will, subject to approval, indirectly own certain of Paramount's existing assets with current production of approximately 25,000 Boe/d (80 percent natural gas). These assets, in the Kaybob and Marten Creek areas of Alberta, are primarily low-risk, high working interest properties that are geographically concentrated with numerous infill drilling opportunities and good access to infrastructure and processing facilities to be operated and controlled by Trilogy. The balance of Paramount's assets, consisting of its predominantly growth-oriented assets, will remain with Paramount. Current production from these assets is approximately 20,000 Boe/d (75 percent natural gas). Through Paramount, shareholders will participate in the potential upside of its remaining predominantly growth-oriented assets. Through Trilogy, unitholders will receive regular distributions of cash derived from the cash flow produced by Trilogy's low-risk development assets.

Due to Trilogy's extensive development drilling portfolio, it is anticipated that Trilogy will retain approximately 35 percent of its cash flow for capital expenditures with the remaining 65 percent of its cash flow being distributed to unitholders in monthly distributions. This extensive development drilling portfolio is expected to make Trilogy less reliant on the competitive acquisition market for developed assets to maintain and grow distributions. Paramount believes that the Trust Spinout will enhance value for shareholders by dividing Paramount's assets into two specific groups, consisting of (i) the

higher free cash flow Kaybob and Marten Creek assets which will be owned through Trilogy, and (ii) the predominantly growth oriented assets that will continue to be owned by Paramount. The Trust Spinout will allow shareholders to participate either separately or on a combined basis in the growth potential and low-risk development qualities of Paramount's assets.

Paramount believes that the post-transaction structure better aligns risks and returns from each asset class in a way that is both sustainable and tax effective. If the necessary securityholder and court approvals are obtained and other conditions are satisfied, the Trust Spinout is expected to be completed on or about April 1, 2005.

NOTE REDEMPTION

On December 30, 2004 the Company redeemed approximately US$41.7 million of the 7 7/8 percent Senior Notes due 2010 and US$43.7 million of the 8 7/8 percent notes due 2014. The indentures governing the notes permit the Company to redeem up to 35 percent of the aggregate principal amount of each series of notes outstanding. The redemptions were made pursuant to the rights offering arising from the Company's October equity offerings.

NOTE EXCHANGE

On December 17, 2004, Paramount commenced the exchange offer and consent solicitation for its 7 7/8 percent Senior Notes due 2010 (the "2010 Notes") and 8 7/8 percent Senior Notes due 2014 (the "2014 Notes"). On February 7, 2005, the Company completed the notes offer by issuing US$213.6 million principal amount of 2013 notes and paying aggregate cash consideration of approximately US$36.2 million in exchange for approximately 99.31 percent of the 2010 notes and 100 percent of the 2014 notes. The 2013 notes bear interest at a rate of 8 1/2 percent per annum and mature January 31, 2013. The notes are secured by approximately 80 percent of the Trust units that will be owned by Paramount following completion of the Trust Spinout (see Reorganization Announcement above).

EQUITY ISSUANCE

On October 26, 2004, Paramount completed its public offering of 2,500,000 common shares (including 500,000 common shares issued following the exercise in full of the underwriters' option) at a price of $23.00 per share for gross proceeds of $57.5 million.

On October 15, 2004, Paramount completed the private placement of 2,000,000 common shares issued on a "flow-through" basis at $29.50 per share. The gross proceeds of the issue were $59 million.

DISPOSITION OF ASSETS

On July 27, 2004, Wilson Drilling Ltd. ("Wilson"), a private drilling company in which Paramount owns a 50 percent equity interest, closed the sale of its drilling assets for $32 million to a publicly traded Income Trust. The gross proceeds were $19.2 million in cash with the balance in exchangeable shares. The exchangeable shares can be redeemed for trust units in the Income Trust, subject to customary securities laws and regulations. In connection with the closing of the sale, certain indebtedness related to these operations has been extinguished.

$87 MILLION ASSET ACQUISITION

On August 16, 2004, Paramount completed the acquisition of assets in the Marten Creek area in Grande Prairie for $86.9 million, after adjustments. The assets acquired were producing approximately 14 MMcf/d of natural gas, or 2,300 Boe/d. The reserves attributable to the properties as of July 1, 2004, as estimated by McDaniel and Associates, consist of proved reserves of approximately 17.4 Bcf of natural gas, or 2.9 million Boe; proved plus probable reserves of approximately 22.2 Bcf or 3.7 million Boe. The asset retirement associated with these assets is $2.1 million. In accounting for this acquisition, the Company recorded a future tax asset in the amount of $89.0 million.

$185 MILLION ASSET ACQUISITION

On June 30, 2004, Paramount completed the acquisition of assets in the Kaybob area of central Alberta and the Fort Liard area of the Northwest Territories for $185.1 million, after adjustments. The properties acquired were producing approximately 10,000 Boe/d, comprised of 40 MMcf/d of natural gas and 3,300 Bbl/d of oil and natural gas liquids ("NGLs"). The reserves attributable to the properties as of June 1, 2004 were estimated by Paramount to consist of proved reserves of approximately 47.2 Bcf of natural gas and 4.4 million Bbl of oil and NGLs, or a total of 12.3 million Boe;

proved plus probable reserves of approximately 93.6 Bcf of natural gas and 6.7 million Bbl of oil and NGLs, or a total of 22.2 million Boe.

On August 12, 2004, Paramount disposed of the Notikewan assets acquired in the $185 million asset acquisition for approximately $20 million. No gain or loss was recorded on the transaction.

ISSUANCE OF US $125 MILLION OF LONG-TERM SENIOR NOTES

On June 29, 2004, the Company issued US$125 million 8 7/8 percent Senior Notes due 2014. Proceeds from the Senior Notes issuance were used to partially finance the $185 million asset acquisition. Interest on the notes is payable semi-annually, beginning in 2005. The Company may redeem some or all of the notes at any time after July 15, 2009, at redemption prices ranging from 100 percent to 104.438 percent of the principal amount, plus accrued and unpaid interest to the redemption date, depending on the year in which the notes are redeemed. In addition, the Company may redeem up to 35 percent of the notes prior to July 15, 2007 at 108.875 percent of the principal amount, plus accrued interest to the redemption date, using the proceeds of certain equity offerings. The notes are unsecured and rank equally with all the Company's existing and future senior unsecured indebtedness. The financing charges related to the issuance of the senior notes are capitalized to other assets and amortized evenly over the term of the notes.

REVENUE & PRODUCTION

Revenue (thousands of dollars)	**2004**	2003	2002
Natural gas, net of transportation	**$ 425,626**	$ 333,924	$ 311,438
Oil and natural gas liquids, net of transportation	**124,990**	100,135	72,750
Petroleum and natural gas revenue	**550,616**	434,059	384,188
Realized financial instrument gain (loss)	**(683)**	(53,204)	46,813
Unrealized financial instrument gain	**19,376**	-	-
Gain (loss) on investments	**(34)**	(1,020)	40,830
Gross revenue before royalties	**$ 569,275**	$ 379,835	$ 471,831

Petroleum and natural gas revenue totaled $550.6 million in 2004, as compared to $434.1 million in 2003 (2002 - $384.2 million). The increase in revenue is due to increased production and higher commodity prices. Stronger natural gas demand resulted in an increase of 12 percent in Paramount's average natural gas sales price before financial instruments to $6.72/Mcf as compared to $5.99/Mcf in 2003 (2002 - $3.53/Mcf). The Company's average natural gas price after financial instruments was $6.86/Mcf as compared to $5.16/Mcf in 2003 (2002 - $4.08/Mcf). Natural gas production volumes averaged 173 MMcf/d in 2004, a 13 percent increase from the 153 MMcf/d produced in 2003 (2002 – 241 MMcf/d), primarily as a result of acquisitions made during the year.

Oil and natural gas liquids ("NGLs") production averaged 7,297 Bbl/d in 2004, a two percent increase from 2003's average production of 7,169 Bbl/d. Paramount's average oil and NGLs sales price before financial instruments was $46.80/Bbl in 2004 compared to $38.27/Bbl in 2003, primarily due to stronger market prices. In addition, the Company's average oil and NGLs price increased due to a change in product mix as a result of NGLs and light oil properties acquired in 2004 replacing medium grade properties disposed of in October 2003.

Paramount's 2004 production profile continued to be significantly weighted to natural gas. In 2004 natural gas production contributed 80 percent of Paramount's total production compared to 78 percent in 2003 (2002 – 88 percent).

Fourth quarter petroleum and natural gas revenue before financial instruments totaled $165.8 million as compared to $86.1 million for the comparable quarter in 2003 (2002 - $135.0 million). The increase in revenue is due to increased production volumes and to higher commodity prices. Natural gas production volumes averaged 198 MMcf/d during the fourth quarter, an increase of 40 percent as compared to 141 MMcf/d for the comparable quarter in 2003 (2002 – 263 MMcf/d). The increase in natural gas production is primarily a result of production from acquired properties during the year. Oil and NGLs sales averaged 8,903 Bbl/d in the fourth quarter of 2004 as compared to 5,877 Bbl/d for the comparable quarter in 2003 (2002 – 8,552 Bbl/d). Increased oil and NGLs production during the fourth quarter of 2004 is mainly the result of increased NGLs production associated with the properties acquired combined with a decrease in oil and NGLs production resulting from the sale of Sturgeon Lake in October 2003.

The Alberta Securities Commission released National Instrument 51-101 (the "Instrument") in 2003, with an effective date of September 30, 2003. The Instrument requires all reported petroleum and natural gas production to be measured in marketable quantities, with adjustments for heat content included in the commodity price reported. Commencing the fourth quarter of 2003 the Company adopted the Instrument prospectively. As such, fourth quarter 2003 and subsequent period natural gas production volumes are measured in marketable quantities, with adjustments for heat content and transportation reflected in the reported natural gas price.

FINANCIAL INSTRUMENTS

Paramount's financial success is contingent upon the growth of reserves and production volumes and the economic environment that creates a demand for natural gas and crude oil. Such growth is a function of the amount of cash flow that can be generated and reinvested into a successful capital expenditure program. To protect cash flow against commodity price volatility, the Company will, from time to time, manage cash flow by utilizing commodity price hedges. The financial instrument program is generally for periods of less than one year and would not exceed 50 percent of Paramount's current production volumes.

At December 31, 2004, Paramount had the following commodity price financial instrument contracts in place:

	Amount	Price	Term
Sales Contracts			
NYMEX Fixed Price	10,000 MMbtu/d	US$ 6.41	November 2004 - March 2005
NYMEX Fixed Price	10,000 MMbtu/d	US$ 7.46	November 2004 - March 2005
NYMEX Fixed Price	10,000 MMbtu/d	US$ 7.95	November 2004 - March 2005
AECO Fixed Price	20,000 GJ/d	$ 7.90	November 2004 - March 2005
AECO Fixed Price	20,000 GJ/d	$ 8.03	November 2004 - March 2005
AECO Fixed Price	20,000 GJ/d	$ 7.60	November 2004 - March 2005
NYMEX Call Option	20,000 MMbtu/d	US$ 10.00 Strike	December 2004 - March 2005
AECO Fixed Price	20,000 GJ/d	$ 6.28	April 2005 - June 2005
AECO Fixed Price	20,000 GJ/d	$ 6.30	April 2005 - June 2005
AECO Fixed Price	20,000 GJ/d	$ 6.80	April 2005 - June 2005
Purchase Contracts			
AECO Fixed Price	20,000 GJ/d	$ 6.76	November 2004 - March 2005

Had these financial contracts been settled on December 31, 2004, using prices in effect at that time, the mark to market before tax gain would have totaled $14.2 million.

As at December 31, 2004, the Company had entered into the following physical delivery contracts:

	Amount	Price	Term
Physical Delivery Contracts			
Station 2 Fixed Price	8,000 GJ/d	$ 7.99	November 2004 - March 2005
Station 2 Fixed Price	12,000 GJ/d	$ 8.00	November 2004 - March 2005

Subsequent to December 31, 2004, the Company has entered into the following financial instrument contracts:

	Amount	Price	Term
Sales Contracts			
NYMEX Fixed Price	1,000 Bbl/d	US$ 46.77	March 2005 - December 2005
NYMEX Fixed Price	1,000 Bbl/d	US$ 47.30	March 2005 - September 2005
NYMEX Fixed Price	1,000 Bbl/d	US$ 53.26	April 2005 - September 2005
AECO Fixed Price	10,000 GJ/d	$ 7.06	April 2005 - October 2005
AECO Fixed Price	10,000 GJ/d	$ 7.10	April 2005 - October 2005

On January 1, 2004, the Company adopted the recommendations set out by the Canadian Institute of Chartered Accountants ("CICA") in Accounting Guideline ("AcG") 13 – Hedging Relationships and Emerging Issues Committee Abstract 128 – Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments. According to the

recommendations, financial instruments that do not qualify as a hedge under AcG 13 or are not designated as a hedge are recorded in the consolidated balance sheets as either an asset or a liability, with changes in fair value recorded in net earnings. The Company has chosen not to designate any of its financial instruments as hedges and accordingly, has used mark-to-market accounting for these instruments.

As a result of applying these recommendations, the Company recorded deferred financial instrument gains and losses at January 1, 2004 of $3.3 million and $1.8 million, respectively, representing the fair values of financial contracts outstanding at the beginning of the fiscal year. These deferred gains and losses are being recognized in the earnings over the term of the related contracts. Amortization for the year ended December 31, 2004 totaled $1.8 million for the deferred financial instrument loss and $1.6 million for the deferred financial instrument gain, for a net decrease in earnings before tax of $0.2 million.

In addition, the Company recorded a net financial instrument asset at December 31, 2004, with a fair value of $19.4 million. This amount reflects the unrealized changes in fair value of Paramount's financial instruments.

The total gain on financial instruments for the period of $18.7 million is comprised of unrealized gains of $19.4 million (change in fair value of contracts recorded on transition - $1.3 million gain, amortization of the fair value of contracts - $0.2 million loss, fair value of contracts entered into during the period - $18.3 million gain) less realized losses of $0.7 million. The $0.7 million realized cash losses on financial instruments for the year ended December 31, 2004 is a 99 percent decrease from the $53.2 million of realized cash losses on financial instruments for the 2003 comparative period.

The Company is exposed to credit risk from financial instruments to the extent of non-performance by third parties, and non-performance by counterparties to swap agreements. The Company minimizes credit risk associated with possible non-performance by financial instrument counterparties by entering into contracts with only highly rated counterparties and controls third party credit risk with credit approvals, limits on exposures to any one counterparty, and monitoring procedures.

During 2004, approximately 65 percent of Paramount's natural gas sales were under long-term contracts to gas aggregators and direct-sales purchasers as compared to 75 percent and 43 percent for 2003 and 2002, respectively. The decrease in the percentage is due to decreased aggregator gas sales as well as termination of the Company's Ventura northern border agreement.

Paramount closed a transaction in March 2005 whereby it acquired an indirect 25 percent ownership interest in a gas marketing limited partnership. In conjunction with the acquisition of the ownership interest, Paramount will make available for delivery an average of 150 million GJ/d of natural gas over a five year term, to be marketed on Paramount's behalf by the gas marketing limited partnership.

Paramount and Summit Operating Partnership (which will become Trilogy Energy LP, subject to the completion of the Trust Spinout) have entered into a Call on Production Agreement. Under this agreement, Paramount will have the right to purchase all or any portion of Trilogy Energy LP's available gas production at a price no less favourable than the price Paramount will receive on the resale of the natural gas to the gas marketing limited partnership. The term of the Call on Production Agreement will be no longer than five years.

Paramount is not entitled to demand collateral securities from the gas marketing limited partnership to ensure payment for the gas volumes delivered, but is entitled to other means of protection in this regard including stringent credit and risk management restrictions.

NETBACKS

Netbacks ($/Boe)		2004		2003		2002
P&NG revenue, net of transportation	$	**41.61**	$	36.36	$	25.50
Royalties		**7.94**		6.93		4.44
Operating costs		**7.24**		6.82		5.14
Operating netback		**26.43**		22.61		15.92
Realized financial instrument loss (gain)		**0.05**		4.47		(2.79)
General and administrative		**1.91**		1.60		0.95
Bad debt expense (recovery)		**(0.42)**		0.50		-
Lease rentals		**0.27**		0.30		0.27
Interest on long-term debt (1)		**1.82**		1.60		1.43
Current and Large Corporations Tax		**0.51**		0.23		0.55
Cash flow netback	$	**22.29**	$	13.91	$	15.51

(1) Net of non-cash interest expense.

ROYALTIES

Royalties (thousands of dollars)		2004		2003		2002
Crown royalties (net of ARTC)	$	**99,298**	$	78,996	$	70,786
Other royalties		**5,748**		3,516		3,658
Net royalties	$	**105,046**	$	82,512	$	74,444
Average corporate royalty rate as a percentage of petroleum and natural gas revenue before financial instruments		**19.1%**		19.0%		19.4%

For 2004, net royalties increased to $105.0 million from $82.5 million in 2003 (2002 – $74.4 million) due to higher production and commodity prices. As a percentage of revenue, Paramount's corporate royalty rate is substantially unchanged from the prior year, at 19.1 percent compared to 19.0 percent in 2003.

Fourth quarter royalties totaled $30.4 million as compared to $10.7 million for the fourth quarter in 2003 (2002 - $28.2 million). The increase in royalty costs reflects the increase in production volumes and higher commodity prices.

OPERATING COSTS

Operating Expenses (thousands of dollars)		2004		2003		2002
Operating expenses	$	**95,767**	$	81,193	$	86,067
Net operating expenses per Boe	$	**7.24**	$	6.82	$	5.14

Paramount's 2004 operating expenses increased 18 percent to $95.8 million from $81.2 million in 2003 (2002 – $86.1 million). On a units-of-production basis, operating costs increased 6 percent to $7.24/Boe from $6.82/Boe in 2003 (2002 – $5.14/Boe). The industry in general experienced increases in the costs of goods and services particularly higher labour and energy costs. In addition, properties acquired by the Company during the year have higher per unit operating costs than existing Paramount properties. Paramount constructs and operates plant facilities and gathering systems as a corporate strategy in order to control the flow of its natural gas to market. These facilities incur fixed costs, which are in addition to the costs incurred at the well level, thereby increasing total operating expenses and the relative magnitude of the per unit costs.

Fourth quarter operating costs increased to $30.9 million as compared to $22.3 million a year earlier. Fourth quarter operating costs decreased on a units-of-production basis to $8.02/Boe from $8.25/Boe for the comparable quarter in 2003. The 2004 fourth quarter operating costs included workovers related to acquired properties, while the fourth quarter of 2003 included the settlement of a dispute with a facility operator, as well as post-closing adjustments related to the Sturgeon Lake property sale incurred during the quarter.

GENERAL AND ADMINISTRATIVE EXPENSES

General and Administrative Expenses (thousands of dollars)	**2004**	2003	2002
Gross general and administrative expenses	**$ 41,007**	$ 31,906	$ 30,868
Operating recoveries	**(15,760)**	(12,855)	(15,238)
Net general and administrative expenses	**$ 25,247**	$ 19,051	$ 15,630
Net general and administrative expenses per Boe	**$ 1.91**	$ 1.60	$ 0.95

General and administrative expenses, net of operating recoveries, increased to $25.2 million in 2004 as compared to $19.1 million in 2003 (2002 - $15.6 million). Paramount has increased its head office staffing levels to enable the Company to identify and develop new core areas and build its production portfolio. This initiative has resulted in Paramount advancing its long-term projects such as Colville Lake, Northeast Alberta bitumen and coal bed methane, and developing successful new fields in existing core areas within Grande Prairie and Northwest Alberta. The Company has also increased administrative staff levels to ensure compliance with new corporate and reporting obligations in Canada and the United States; certain of these are a result of the US debt offerings closed in 2004. Paramount does not capitalize any general and administrative expenses with the exception of overhead recoveries.

STOCK-BASED COMPENSATION

Prior to 2004, the Company accounted for its stock option plan using the fair value method. In 2004, the Company prospectively adopted the intrinsic value method to account for the Company's stock-based compensation plan. For 2004, the Company recorded a $41.2 million non-cash expense using the intrinsic value method compared to the $1.2 million non-cash expense recorded in 2003 (2002 - $0.6 million) using the fair value method.

INTEREST EXPENSE

Interest Expense (thousands of dollars)	**2004**	2003	2002
Interest expense	**$ 25,399**	$ 19,214	$ 23,943
Total debt, December 31	**$ 459,141**	$ 287,237	$ 539,270
Average debt outstanding for the period	**$ 443,156**	$ 340,919	$ 448,951

Interest expense increased to $25.4 million in 2004 from $19.2 million in 2003 (2002 – $23.9 million). The increase reflects higher average debt levels for the Company in 2004 as a result of acquisitions made in the current year.

DRY HOLE COSTS

Under the successful efforts method of accounting, costs of drilling exploratory wells are initially capitalized and, if subsequently determined to be unsuccessful, are charged to dry hole expense. Other exploration costs, including geological and geophysical costs and annual lease rentals, are charged to exploration expense as incurred. For 2004, dry hole costs amounted to $24.7 million as compared to $36.6 million in 2003 (2002 - $120.1 million). The 2004 provision includes $5.8 million of costs associated with wells drilled in the current year and $18.9 million associated with exploratory wells drilled in previous years.

Geological and geophysical expenses increased during 2004 to $8.7 million from $8.5 million in the previous year (2002 - $9.3 million).

DEPLETION, DEPRECIATION AND AMORTIZATION

The current year provision for depletion and depreciation expense totaled $191.6 million as compared to $165.1 million in 2003 (2002 – $169.4 million). Depletion and depreciation expense includes expired lease costs of $12.9 million. On a units-of-production basis, depletion and depreciation costs averaged $14.48/Boe as compared to $13.86/Boe in 2003 (2002 - $10.11/Boe).

Capital costs associated with undeveloped land of $164 million and non-producing petroleum and natural gas properties of $136 million totaling $300 million are excluded from capital costs subject to depletion in 2004 (2003 - $209 million).

ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2004, the Company retroactively adopted, with restatement, the Canadian Institute of Chartered Accountants ("CICA") recommendation on Asset Retirement Obligations, which requires liability recognition for the fair value of retirement obligations associated with long-lived assets. Prior to January 1, 2004, the estimated future dismantlement and site restoration costs of natural gas and crude oil assets were provided for using the unit-of-production method.

As a result of this change, net earnings for the year ended December 31, 2003 decreased by $1.5 million ($0.02 per share). The asset retirement obligations liability as at December 31, 2003 increased by $40.4 million, property, plant and equipment, net of accumulated depletion, increased by $31.1 million, and future income tax liability decreased $3.7 million. Opening 2003 retained earnings decreased by $4.1 million to reflect the cumulative impact of depletion expense and accretion expense, net of the previously recognized cumulative site restoration provision and net of related future income taxes on the asset retirement obligations, recorded retroactively.

On an annual basis the Company reviews the liability for asset retirement obligations. For 2004, accretion expense for asset retirement obligations totaled $6.9 million as compared to $4.0 million in 2003. At December 31, 2004, the Company had recorded an asset retirement obligation liability for its petroleum and natural gas properties of $101.5 million (2003 - $61.6 million). The majority of the increase is due to the obligations associated with additional acquired properties purchased during the year.

INCOME TAXES

In 2004, Paramount recorded Large Corporations and other tax expense of $6.8 million as compared to $2.7 million in 2003.

The future income tax expense recorded for 2004 totaled $40.7 million, as compared to $63.5 million recovery in 2003.

Estimated Income Tax Pools (millions of dollars)	**December 31, 2004**	December 31, 2003
Undepreciated capital costs (UCC)	**$ 257**	$ 215
Canadian oil and gas property expenses (COGPE)	**422**	25
Canadian development expenses (CDE)	**203**	166
Canadian exploration expenses (CEE)	**158**	68
Other	**33**	21
Total estimated income tax pools	**$ 1,073**	$ 495

Paramount has available approximately $1,073 million of unutilized tax pools at December 31, 2004. These tax pools will be available for deduction in 2005 in accordance with Canadian income tax regulations at varying rates of amortization.

CASH FLOW AND EARNINGS

(thousands of dollars)		2004	2003	2002
Cash flow from operations		**$ 295,566**	$ 167,276	$ 259,916
Cash flow from operations per share	- basic	**$ 4.95**	$ 2.78	$ 4.37
	- diluted	**$ 4.84**	$ 2.77	$ 4.36
Net earnings before discontinued operations		**$ 34,895**	$ 1,208	$ 11,132
Net earnings (loss) from discontinued operations		**$ 6,279**	$ (57)	$ (825)
Net earnings		**$ 41,174**	$ 1,151	$ 10,307
Earnings before discontinued operations per share	- basic	**$ 0.58**	$ 0.02	$ 0.19
	- diluted	**$ 0.57**	$ 0.02	$ 0.19
Earnings per share	- basic	**$ 0.69**	$ 0.02	$ 0.17
	- diluted	**$ 0.67**	$ 0.02	$ 0.16

Paramount's cash flow from operations increased 77 percent to $295.6 million from $167.3 million in 2003. The increase in cash flow was a result of a reduction in realized financial instrument losses in 2004 as compared to 2003, and an increase in revenues due to higher commodity prices and production. This was partially offset by higher operating costs, general and administrative expenses and interest.

Fourth quarter cash flow totaled $92.1 million, an increase of 113 percent from $43.2 million during the same period in 2003 (2002 - $62.1 million). The increase in cash flow is a result of higher production levels and increased commodity prices as compared to the fourth quarter of 2003.

The Company recorded net earnings of $41.2 million for the year ended 2004, as compared to net earnings of $1.2 million in 2003. The higher earnings in 2004 are primarily due to an increase in petroleum and natural gas sales resulting from higher production and commodity prices, financial instrument gains in 2004 as opposed to 2003 losses, and unrealized foreign exchange gains on US debt. This was partially offset by higher non-cash stock based compensation expense, depletion and depreciation expense, and future income tax expense.

QUARTERLY INFORMATION

Historical quarterly information, prepared by the Company in Canadian dollars and in accordance with GAAP, is as follows:

		Fiscal 2004 Three Months Ended			
(thousands of dollars, except per share amounts)		**Dec. 31**	**Sep. 30**	**June 30**	**Mar. 31**
Net revenues		**$ 162,880**	$ 127,192	$ 95,767	$ 79,179
Net earnings (loss) before discontinued operations		**$ (18,873)**	$ 40,599	$ 10,331	$ 2,838
Net earnings (loss) from discontinued operations		**$ 1,120**	$ 5,213	$ (395)	$ 341
Net earnings (loss)		**$ (17,753)**	$ 45,812	$ 9,936	$ 3,179
Net earnings (loss) before discontinued operations					
per common share	- basic	**$ (0.30)**	$ 0.69	$ 0.18	$ 0.05
	- diluted	**$ (0.29)**	$ 0.68	$ 0.17	$ 0.05
Net earnings (loss) per common share	- basic	**$ (0.28)**	$ 0.78	$ 0.17	$ 0.05
	- diluted	**$ (0.28)**	$ 0.76	$ 0.17	$ 0.05

		Fiscal 2003 Three Months Ended			
(thousands of dollars, except per share amounts)		**Dec. 31**	**Sept. 30**	**June 30**	**Mar. 31**
Net revenues		$ 76,945	$ 65,415	$ 65,101	$ 91,446
Net earnings (loss) before discontinued operations		$ 10,899	$ (8,491)	$ (1,105)	$ (95)
Net earnings (loss) from discontinued operations		$ 209	$ 108	$ (783)	$ 409
Net earnings (loss)		$ 11,108	$ (8,383)	$ (1,888)	$ 314
Net earnings (loss) before discontinued operations					
per common share	- basic	$ 0.18	$ (0.14)	$ (0.02)	$ -
	- diluted	$ 0.18	$ (0.14)	$ (0.02)	$ -
Net earnings (loss) per common share	- basic	$ 0.18	$ (0.14)	$ (0.03)	$ 0.01
	- diluted	$ 0.18	$ (0.14)	$ (0.03)	$ 0.01

Quarterly net revenues have continued to increase since June 30, 2003, primarily as a result of an increase in production levels and higher commodity prices. The decrease in net revenue between March 31, 2003 and June 30, 2003 is primarily due to lower production volumes resulting from the disposition of assets to Paramount Energy Trust in the first quarter of 2003. The third and fourth quarter net revenues for 2004 reflect increased production resulting from the acquisition of assets in the Kaybob, East Liard, and Marten Creek areas.

Quarterly net earnings are generally lower in 2003 due to lower production levels, combined with higher financial instrument losses incurred during 2003. The net loss in the fourth quarter of 2004 is primarily due to the Company prospectively adopting the intrinsic value method to account for stock based compensation expense and an increase in future tax expense.

CAPITAL EXPENDITURES

Capital Expenditures (thousands of dollars)	**2004**	2003	2002
Land	**$ 37,919**	$ 22,288	$ 6,410
Geological and geophysical	**8,728**	8,450	9,303
Drilling	**184,466**	123,455	124,076
Production equipment and facilities	**85,171**	69,560	77,407
Exploration and development expenditures	**316,284**	223,753	217,196
Summit Resources Limited acquisition	**-**	-	251,422
Property acquisitions	**322,598**	937	28,610
Proceeds on property dispositions	**(61,806)**	(371,601)	(5,042)
Other	**1,938**	1,933	2,349
Net capital expenditures	**$ 579,014**	$ (144,978)	$ 494,535
Property, plant and equipment, net, December 31	**$ 1,345,806**	$ 1,037,307	$ 1,411,961
Total assets, December 31	**$ 1,542,786**	$ 1,177,130	$ 1,526,786

During 2004, expenditures for exploration and development activities totaled $316.3 million as compared to $223.8 million in 2003 (2002 – $217.2 million). The increase in the capital expenditures program in 2004 resulted in a total of 271 gross (180 net) wells drilled during the year, compared to 211 gross (139 net) wells in 2003 (2002 – 135 gross, 99 net).

Net capital expenditures totaled $579.0 million in 2004 as compared to a recovery of $145 million in 2003 (2002 – $494.5 million). The Company acquired a number of properties totaling $322.6 million in 2004 offset by the disposition of certain non-core properties.

Paramount has budgeted a total of $340 million for capital expenditures for 2005; $100 million of which is to be directed to the Trilogy assets and the remaining $240 million will be directed to the properties retained by Paramount Resources Ltd. The 2005 capital expenditure program is expected to be funded through the Company's 2005 cash flow.

INVESTMENTS

The Company has the following short-term investments:

Investments	Opening 2004 Shares	Acquired (Divested)	Closing 2004 Shares	Investment
Fox Creek Petroleum Corp.	2,325,162	-	2,325,162	$ 2,538,000
Invertek (1)	-	-	-	560,114
Trinidad Drilling Ltd. (1)(2)	-	820,513	820,513	6,400,001
Arctos Petroleum Corp. (6)	-	-	-	2,116,945
Harvest Energy Trust	200,000	(200,000)	-	-
Jurassic Oil and Gas Ltd. (3)	850,000	-	850,000	-
Jurassic Oil and Gas Ltd. - Demand Note (4)	-	-	-	100,000
USD short-term deposits (5)	-	-	-	13,268,200
	3,375,162	620,513	3,995,675	$24,983,260

(1) Investment in Invertek and Trinidad Drilling Ltd. is through Wilson Drilling Ltd.
(2) Investment is in the form of Exchangeable Shares which can be redeemed for trust units in Trinidad Energy Services Income Trust.
(3) The Company wrote off its investment in Jurassic Oil and Gas Ltd. in 2003 but has retained the shares.
(4) Bears interest at 6 percent per annum.
(5) US$5 million matures January 4, 2005 and bears interest at 2.15 percent per annum. US$6 million matures January 14, 2005 and bears interest at 2.23 percent per annum.
(6) Investment is in the form of convertible debentures maturing March 1, 2005 bearing interest at 8 percent per annum.

LIQUIDITY AND CAPITAL RESOURCES

Paramount's capital structure as at December 31, 2004, was as follows:

(thousands of dollars, except per share amounts)	Amount	%	$/Share(1)
Debt			
US$ senior notes	$ 257,836	24	$ 4.08
Credit facility	201,305	19	3.19
Working capital surplus	(7,954)	(1)	(0.13)
Net debt	451,187	42	7.14
Shareholders' equity	625,039	58	9.89
Total capitalization	$ 1,076,226	100%	$ 17.03

(1) At December 31, 2004 – 63,185,600 basic common shares outstanding.

DEBT

US$ SENIOR NOTES

The Company issued US$175 million of 7 7/8 percent Senior Notes due 2010 on October 27, 2003. Interest on the notes is payable semi-annually, beginning in 2004. The Company may redeem some or all of the notes at any time after November 1, 2007 at redemption prices ranging from 100 percent to 103.938 percent of the principal amount, plus accrued and unpaid interest to the redemption date, depending on the year in which the notes are redeemed. In addition, the Company may redeem up to 35 percent of the notes prior to November 1, 2006 at 107.875 percent of the principal amount, plus accrued interest to the redemption date, using the proceeds of certain equity offerings. The notes are unsecured and rank equally with all of the Company's existing and future senior unsecured indebtedness.

On June 29, 2004, the Company issued US$125 million of 8 7/8 percent Senior Notes due 2014. Interest on the notes is payable semi-annually, beginning in 2005. The Company may redeem some or all of the notes at any time after July 15, 2009 at redemption prices ranging from 100 percent to 104.438 percent of the principal amount, plus accrued and unpaid interest to the redemption date, depending on the year in which the notes are redeemed. In addition, the Company may redeem up to 35 percent of the notes prior to July 15, 2007 at 108.875 percent of the principal amount, plus accrued interest to the redemption date, using the proceeds of certain equity offerings. The notes are unsecured and rank equally with all of the Company's existing and future senior unsecured indebtedness.

On December 30, 2004, the Company redeemed US$41.7 million principal of its 7 7/8 percent Senior Notes due 2010 and US$43.8 million principal of its 8 7/8 percent Senior Notes due 2014. The aggregate redemption price was US$45.0 million and US$47.6 million plus accrued and unpaid interest for the 7 7/8 percent Senior Notes and 8 7/8 percent Senior Notes respectively.

CREDIT FACILITY

As at December 31, 2004, the Company had a $270 million committed revolving/non-revolving term facility with a syndicate of Canadian chartered banks. Borrowings under the facility bear interest at the lenders' prime rate, bankers' acceptance or LIBOR rates plus an applicable margin, dependent on certain conditions. The revolving nature of the facility is due to expire on March 31, 2005. The Company has requested and received approval for an extension on the revolving credit facility of 364 days. Advances drawn on the facility are secured by a fixed charge over the assets of the Company.

In February 2005, the Company's borrowing capacity under this facility was increased to $330 million as a result of the Company's Senior Note redemption on December 31, 2004, and an increase in its oil and natural gas reserves.

WORKING CAPITAL

The Company's working capital surplus at December 31, 2004 was $8.0 million (2003 - $10.5 million deficiency).

FUTURE COMMITMENTS

Future commitments, as at December 31, 2004, are as follows:

		Expected Payment Date			
Contractual Obligations (thousands of dollars)	**Total**	**Less than 1 year**	**2-3 years**	**4-5 years**	**After 5 years**
US$ 7 7/8% Senior Notes due 2010	$ 160,174	$ -	$ -	$ -	$ 160,174
US$ 8 7/8% Senior Notes due 2014	97,662	-	-	-	97,662
Pipeline commitments	237,205	22,015	42,504	42,075	130,611
Total	$ 495,041	$ 22,015	$ 42,504	$ 42,075	$ 388,447

SHARE CAPITAL

As at December 31, 2004, the Company's issued share capital consisted of 63,185,600 common shares (December 31, 2003 – 60,094,600 common shares). Changes in share capital were as follows:

Common shares	**Number**	**Consideration** (thousands of dollars)
Balance December 31, 2002	59,458,600	$ 190,193
Stock options exercised	710,000	10,317
Expenses recognized in respect of stock-based compensation	(74,000)	(236)
Balance December 31, 2003	60,094,600	$ 200,274
Shares repurchased - at carrying value	(1,629,500)	(5,322)
Stock options exercised	220,500	3,057
Common shares issued	2,500,000	54,901
Flow-through shares issued	2,000,000	57,981
Tax adjustment on share issuance costs and flow-through share renunciations		(7,959)
Balance December 31, 2004	63,185,600	$ 302,932

Between January 1 and May 14, 2004 the Company repurchased 1,629,500 shares at a carrying value of $5.3 million for $19.4 million.

During the year, employees of the Company exercised 220,500 stock options for total consideration of $3.1 million.

In October 2004, Paramount completed a public offering of 2.5 million common shares at $23.00 per share and a private placement of 2.0 million "flow through" common shares at $29.50 per share. Aggregate gross proceeds from these two offerings were $116.5 million. As at December 31, 2004, the Company had made renunciations of $23.7 million.

STOCK OPTIONS

The Company has an Employee Incentive Stock Option plan (the "plan"). Under the plan, stock options are granted at the current market price on the day prior to issuance. Participants in the plan, upon exercising their stock options, may request to receive either a cash payment equal to the difference between the exercise price and the market price of the Company's common shares or common shares issued from Treasury. Irrespective of the participant's request, the Company may choose to only issue common shares. Cash payments made in respect of the plan are charged to general and administrative expenses when incurred. Options granted vest over four years and have a four and a half year contractual life.

As at December 31, 2004, 5.0 million shares were reserved for issuance under the Company's Employee Incentive Stock Option Plan, of which 3.2 million options are outstanding, exercisable to May 31, 2009, at prices ranging from $8.91 to $26.29 per share.

Stock options	**2004**			2003		
		Average Grant Price	**Options**		Average Grant Price	Options
Balance, beginning of year	**$**	**9.64**	**3,632,000**	$	14.25	1,949,500
Granted		**17.09**	**348,000**		9.66	2,998,000
Exercised		**9.97**	**(618,500)**		14.29	(791,000)
Cancelled		**9.09**	**(149,000)**		10.30	(524,500)
Balance, end of year	**$**	**10.41**	**3,212,500**	$	9.64	3,632,000
Options exercisable, end of year	**$**	**10.26**	**1,282,875**	$	10.72	1,087,875

RISKS AND UNCERTAINTIES

Companies involved in the exploration for and production of oil and natural gas face a number of risks and uncertainties inherent in the industry. The Company's performance is influenced by commodity pricing, transportation and marketing constraints and government regulation and taxation.

Natural gas prices are influenced by the North American supply and demand balance as well as transportation capacity constraints. Seasonal changes in demand, which are largely influenced by weather patterns, also affect the price of natural gas.

Stability in natural gas pricing is available through the use of short and long-term contract arrangements. Paramount utilizes a combination of these types of contracts, as well as spot markets, in its natural gas pricing strategy. As the majority of the Company's natural gas sales are priced to US markets, the Canada/US exchange rate can strongly affect revenue.

Oil prices are influenced by global supply and demand conditions as well as for worldwide political events. As the price of oil in Canada is based on a US benchmark price, variations in the Canada/US exchange rate further affect the price received by Paramount for its oil.

The Company's access to oil and natural gas sales markets is restricted, at times, by pipeline capacity. In addition, it is also affected by the proximity of pipelines and availability of processing equipment. Paramount attempts to control as much of its marketing and transportation activities as possible in order to minimize any negative impact from these external factors.

The oil and gas industry is subject to extensive controls, royalties, regulatory policies and income taxes imposed by the various levels of government. These controls and policies, as well as income tax laws and regulations, are amended from time to time. The Company has no control over government intervention or taxation levels in the oil and gas industry; however, it operates in a manner intended to ensure that it is in compliance with all regulations and is able to respond to changes as they occur.

Paramount's operations are subject to the risks normally associated with the oil and gas industry including hazards such as unusual or unexpected geological formations, high reservoir pressures and other conditions involved in drilling and

operating wells. The Company attempts to minimize these risks using prudent safety programs and risk management, including insurance coverage against potential losses.

The Company recognizes that the industry is faced with an increasing awareness with respect to the environmental impact of oil and gas operations. Paramount has reviewed the environmental risks to which it is exposed and has determined that there is no current material impact on the Company's operations; however, the cost of complying with environmental regulations is increasing. Paramount intends to ensure continued compliance with environmental legislation.

2005 OUTLOOK AND SENSITIVITY ANALYSIS

The Company's earnings and cash flow are highly sensitive to changes in commodity prices, exchange rates and other factors that are beyond the control of the Company. Current volatility in commodity prices creates uncertainty as to Paramount's cash flow and capital expenditure budget. The Company will therefore assess results throughout the year and revise estimates as necessary to reflect most current information. The following analysis assesses the magnitude of these sensitivities on the Company's 2005 cash flow using the following base assumptions:

2005 Average Production	
Natural gas	210 MMcf/d
Crude oil/liquids	10,000 Bbl/d
2005 Average Prices	
Natural gas	$6.50/Mcf
Crude oil (WTI)	US$42.00/Bbl
2005 Exchange Rate (C$/US$)	$0.81

The following analysis assesses the estimated impact on cash flow with variations in production, prices, interest and exchange rates:

Sensitivity	Cash Flow Effect (millions of dollars)
Gas sales change of 10 MMcf/d	$ 18.98
Gas price change of $0.10/Mcf	$ 6.13
Oil and natural gas liquids sales change of 100 Bbl/d	$ 1.27
Oil and natural gas liquids price change of $1.00/Bbl (WTI)	$ 3.60
Sensitivity to Canada/US exchange rate fluctuation of $0.01 CDN	$ 1.21
Average interest rate change of 1%	$ 0.62

CRITICAL ACCOUNTING ESTIMATES

The MD&A is based on the Company's consolidated financial statements, which have been prepared in Canadian dollars in accordance with Canadian GAAP. The application of Canadian GAAP requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Paramount bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances. Actual results could differ from these estimates under different assumptions or conditions.

The following is a discussion of the critical accounting estimates that are inherent in the preparation of the Company's consolidated financial statements and notes thereto.

ACCOUNTING FOR PETROLEUM AND NATURAL GAS OPERATIONS

Under the successful efforts method of accounting, the Company capitalizes only those costs that result directly in the discovery of petroleum and natural gas reserves, including acquisitions, successful exploratory wells, development costs and the costs of support equipment and facilities. Exploration expenditures, including geological and geophysical costs, lease rentals, and exploratory dry holes are charged to earnings in the period incurred. Certain costs of exploratory wells

are capitalized pending determination that proved reserves have been found. Such determination is dependent upon, among other things, the results of planned additional wells and the cost of required capital expenditures to produce the reserves found.

The application of the successful efforts method of accounting requires management's judgment to determine the proper designation of wells as either developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred. The results of a drilling operation can take considerable time to analyze, and the determination that proved reserves have been discovered requires both judgment and application of industry experience. The evaluation of petroleum and natural gas leasehold acquisition costs requires management's judgment to evaluate the fair value of exploratory costs related to drilling activity in a given area.

RESERVE ESTIMATES

Estimates of the Company's reserves included in its consolidated financial statements are prepared in accordance with guidelines established by the Alberta Securities Commission. Reserve engineering is a subjective process of estimating underground accumulations of petroleum and natural gas that cannot be measured in an exact manner. The process relies on interpretations of available geological, geophysical, engineering and production data. The accuracy of a reserve estimate is a function of the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgment of the persons preparing the estimate.

Paramount's reserve information is based entirely on estimates prepared by its independent petroleum consultants. Estimates prepared by others may be different than these estimates. Because these estimates depend on many assumptions, all of which may differ from actual results, reserve estimates may be different from the quantities of petroleum and natural gas that are ultimately recovered. In addition, the results of drilling, testing and production after the date of an estimate may justify revisions to the estimate.

The present value of future net revenues should not be assumed to be the current market value of the Company's estimated reserves. Actual future prices, costs and reserves may be materially higher or lower than the prices, costs and reserves used for the future net revenue calculations.

The estimates of reserves impact depletion, dry hole and site restoration expenses. If reserve estimates decline, the rate at which the Company records depletion and site restoration expenses increases, reducing net earnings. In addition, changes in reserve estimates may impact the outcome of Paramount's assessment of its petroleum and natural gas properties for impairment.

IMPAIRMENT OF PETROLEUM AND NATURAL GAS PROPERTIES

The Company reviews its proved properties for impairment annually on a field basis. For each field, an impairment provision is recorded whenever events or circumstances indicate that the carrying value of those properties may not be recoverable. The impairment provision is based on the excess of carrying value over fair value. Fair value is defined as the present value of the estimated future net revenues from production of total proved and probable petroleum and natural gas reserves, as estimated by the Company on the balance sheet date. Reserve estimates, as well as estimates for petroleum and natural gas prices and production costs, may change and there can be no assurance that impairment provisions will not be required in the future.

Unproved leasehold costs and exploratory drilling in progress are capitalized and reviewed periodically for impairment. Costs related to impaired prospects or unsuccessful exploratory drilling are charged to earnings. Acquisition costs for leases that are not individually significant are charged to earnings as the related leases expire. Further impairment expense could result if petroleum and natural gas prices decline in the future or if negative reserve revisions are recorded, as it may be no longer economic to develop certain unproved properties. Management's assessment of, among other things, the results of exploration activities, commodity price outlooks and planned future development and sales impacts the amount and timing of impairment provisions.

ASSET RETIREMENT OBLIGATIONS

The asset retirement obligations recorded in the consolidated financial statements are based on estimated total costs of such obligations related to the Company's petroleum and natural gas properties. This estimate is based on management's analysis of production structure, reservoir characteristics and depth, market demand for equipment, currently available procedures and discussions with construction and engineering consultants. Estimating these future costs requires management to make estimates and judgments that are subject to future revisions based on numerous factors, including changing technology and political and regulatory environments.

Beginning in 2004, the Company adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook section 3110 – Asset Retirement Obligation, which will result in changes in accounting for asset retirement obligations. See "Recent Accounting Pronouncements" section.

INCOME TAXES

The Company records future tax assets and liabilities to account for the expected future tax consequences of events that have been recorded in its consolidated financial statements and its tax returns. These amounts are estimates; the actual tax consequences may differ from the estimates due to changing tax rates and regimes, as well as changing estimates of cash flows and capital expenditures in current and future periods. We periodically assess the realizability of our future tax assets. If the Company concludes that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, the tax asset will be reduced by a valuation allowance.

RECENT ACCOUNTING PRONOUNCEMENTS

IMPAIRMENT OF LONG-LIVED ASSETS

The CICA recently issued Handbook Section 3063 - Impairment of Long-Lived Assets. This new section establishes standards for the recognition, measurement and disclosure of the impairment of long-lived assets by profit-oriented enterprises. The section is effective for fiscal years beginning on or after April 1, 2003.

Under the new section, impairment of long-lived assets held for use is determined by a two-step process, with the first step determining when an impairment is recognized and the second step measuring the amount of the impairment. To test for and measure impairment, long-lived assets are grouped at the lowest level for which identifiable cash flows are largely independent. An impairment loss is recognized when the carrying amount of a long-lived asset exceeds the sum of the undiscounted cash flows expected to result from its use and eventual disposition. An impairment loss is measured as the amount by which the long-lived asset's carrying amount exceeds its fair value. This represents a significant change to Canadian GAAP, which previously measured the amount of the impairment as the difference between the long-lived asset's carrying value and its net recoverable amount (i.e. undiscounted cash flows plus residual value).

DISPOSAL OF LONG-LIVED ASSETS AND DISCONTINUED OPERATIONS

The CICA recently issued Handbook Section 3475 - Disposal of Long-Lived Assets and Discontinued Operations, which establishes standards for the recognition, measurement, presentation and disclosure of the disposal of long-lived assets by profit-oriented enterprises. It also establishes standards for the presentation and disclosure of discontinued operations.

Although earlier adoption is encouraged, Section 3475 applies to disposal activities initiated by a company's commitment to a plan on or after May 1, 2003.

VARIABLE INTEREST ENTITIES

The CICA recently issued Accounting Guideline 15 - Consolidation of Variable Interest Entities. The guideline requires the consolidation of entities in which an enterprise absorbs a majority of the entity's expected losses, receives a majority of the entity's expected residual returns, or both, as a result of ownership, contractual or other financial interests in the entity. Currently, entities are generally consolidated by an enterprise when it has a controlling financial interest through ownership of a majority voting interest in the entity. The guideline applies to annual and interim periods beginning on or after November 1, 2004, except for certain disclosure requirements. Entities should provide disclosures about variable interest entities in which they hold significant interests for periods beginning on or after January 1, 2004.

ASSET RETIREMENT OBLIGATIONS

The CICA recently issued Handbook Section 3110 – Asset Retirement Obligation which addresses statutory, regulatory, contractual and other legal obligations associated with the retirement of a long-lived asset that results from its acquisition, construction, development or normal operation.

Under Section 3110, asset retirement obligations are initially measured at fair value at the time the obligation is incurred with a corresponding amount capitalized as part of the asset's carrying value and depreciated over the asset's useful life using a systematic and rational allocation method.

On initial recognition, the fair value of an asset retirement obligation is determined based upon the expected present value of future cash flows. In subsequent periods, the carrying amount of the liability would be adjusted to reflect (a) the passage of time, and (b) revisions to either the timing or the amount of the original estimate of undiscounted cash flows.

The change in liability due to the passage of time is measured by applying an interest method of allocation to the opening liability and is recognized as an increase in the carrying value of the liability and an expense. The expense must be recorded as an operating item in the income statement, not as a component of interest expense. A change in the liability resulting from revisions to either the timing or the amount of the original estimate of undiscounted cash flows is recognized as an increase or decrease in the carrying amount of the liability with an offsetting increase or decrease in the carrying amount of the associated asset.

FINANCIAL INSTRUMENTS, OTHER COMPREHENSIVE INCOME AND EQUITY

The CICA is expected to adopt a new standard in 2005 that sets-out comprehensive requirements for recognition and measurement of financial instruments. Under this new standard, an entity would recognize a financial asset or liability only when the entity becomes a party to the contractual provisions of the financial instrument. Financial assets and financial liabilities would, with certain exceptions, be initially measured at fair value. After initial recognition, the measurement of financial assets would vary depending on the category of the asset: financial assets held for trading (at fair value with the unrealized gains and losses on assets recorded in income), held-to-maturity investments (at amortized cost), loans and receivables (at amortized cost), and available-for-sale financial assets (at fair value with the unrealized gains and losses on assets recorded in comprehensive income). Financial liabilities held for trading would be subsequently measured at fair value while all other financial liabilities would be subsequently measured at amortized cost using the effective interest method.

In conjunction with the proposed new standard on financial instruments as discussed above, a new standard on reporting and display of comprehensive income is also expected. A statement of comprehensive income would be included in a full set of financial statements for both interim and annual periods under this new standard. Comprehensive income is defined as the change in equity (net assets) of an enterprise during a period from transactions and other events and circumstances from non-owner sources. The new statement would present net income and each component to be recognized in other comprehensive income. Likewise, the CICA is expected to adopt a new standard on Equity that would require the separate presentation of: the components of equity (retained earnings, accumulated other comprehensive income, the total of retained earnings and accumulated other comprehensive income, contributed surplus, share capital and reserves); and the changes in equity arising from each of these components of equity.

These new standards are expected to be effective for the year ending December 31, 2006 for the Company.

MANAGEMENT'S REPORT

The accompanying consolidated financial statements of Paramount Resources Ltd. and all the information in this Annual Report are the responsibility of management and have been approved by the Board of Directors.

The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the consolidated financial statements are presented fairly, in all material respects. The financial information contained elsewhere in this report has been reviewed to ensure consistency with the consolidated financial statements.

Management maintains systems of internal accounting and administrative controls of high quality, consistent with reasonable cost. Such systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are appropriately accounted for and adequately safeguarded.

The Audit Committee of the Board of Directors is comprised of non-management directors. The Audit Committee meets quarterly with management as well as the external auditors to discuss auditing matters and financial reporting issues and to satisfy itself that each party is properly discharging its responsibility. The Audit Committee also meets with management and the external auditors to discuss internal controls over the financial reporting process and to review the Annual Report. The Audit Committee reports its findings to the Board of Directors for consideration when approving the consolidated financial statements for issuance to the shareholders. The Audit Committee also considers, for review by the Board of Directors and approval by the shareholders, the engagement or re-appointment of the external auditors.

The consolidated financial statements have been audited by Ernst & Young LLP, the external auditors. Ernst & Young LLP have full and free access to the Audit Committee and management.

Clayton H. Riddell
Chief Executive Officer

Bernard K. Lee
Chief Financial Officer

March 7, 2005

AUDITORS' REPORT

To the Shareholders of Paramount Resources Ltd.

We have audited the consolidated balance sheets of Paramount Resources Ltd. as at December 31, 2004 and 2003 and the consolidated statements of earnings and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004 and 2003 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles. We also report that, in our opinion, these principles have been applied, except for the change in the method of accounting for Asset Retirement Obligations, Financial Instruments, and Stock-Based Compensation and Other Stock-Based Payments as explained in note 2 to the consolidated financial statements, on a basis consistent with that of the preceding year.

Ernst & Young LLP

Chartered Accountants

Calgary, Canada

March 7, 2005

CONSOLIDATED BALANCE SHEETS

As at December 31 (thousands of dollars)	2004	2003 (restated - notes 2 and 5)
ASSETS (note 8)		
Current Assets		
Short-term investments (market value: 2004 - $27,149; 2003 - $17,265)	$ 24,983	$ 16,551
Accounts receivable	107,843	80,710
Financial instruments (note 11)	21,564	-
Prepaid expenses	3,260	2,255
Assets of discontinued operations (note 5)	-	1,680
	157,650	101,196
Property, Plant and Equipment		
Property, plant and equipment, at cost (note 6)	1,933,104	1,444,139
Accumulated depletion and depreciation (note 6)	(587,298)	(418,225)
Assets of discontinued operations, net (note 5)	-	11,393
	1,345,806	1,037,307
Goodwill	31,621	31,621
Other assets	7,709	7,006
	$ 1,542,786	$ 1,177,130
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	$ 147,508	$ 109,334
Financial instruments (note 11)	2,188	-
Liabilities of discontinued operations (note 5)	-	2,455
	149,696	111,789
Long-term debt (note 8)	459,141	287,237
Asset retirement obligations (note 7)	101,486	61,554
Deferred revenue	-	3,959
Stock based compensation liability (note 9)	41,044	-
Future income taxes (note 10)	166,380	206,684
Liabilities of discontinued operations (note 5)	-	9,874
	768,051	569,308
Commitments and Contingencies (note 11 and 14)		
Shareholders' Equity		
Share capital (note 9)		
Issued and outstanding		
63,185,600 common shares (2003 - 60,094,600 common shares)	302,932	200,274
Contributed surplus	-	746
Retained earnings	322,107	295,013
	625,039	496,033
	$ 1,542,786	$ 1,177,130

See accompanying notes to consolidated financial statements.

On behalf of the Board

C. H. Riddell
Director

J.B. Roy
Director

CONSOLIDATED STATEMENTS of EARNINGS and RETAINED EARNINGS

Year Ended December 31 (thousands of dollars except per share amounts)	2004	2003 (restated - notes 2 and 5)
Revenue		
Petroleum and natural gas sales	$ 581,901	$ 464,558
Transportation costs (note 2)	(31,285)	(30,499)
Gain (loss) on financial instruments (note 11)	18,693	(53,204)
Royalties (net of Alberta Royalty Tax Credit)	(105,046)	(82,512)
Loss on sale of investments	(34)	(1,020)
	464,229	297,323
Expenses		
Operating	95,767	81,193
Interest	25,399	19,214
General and administrative	25,247	19,051
Stock based compensation expense (note 9)	41,195	1,214
Bad debt expense (recovery)	(5,523)	5,977
Lease rentals	3,546	3,574
Geological and geophysical	8,728	8,450
Dry hole costs (note 6)	24,676	36,600
(Gain) loss on sales of property, plant and equipment	(16,255)	3,640
Accretion of asset retirement obligations	6,920	4,044
Depletion and depreciation	191,578	165,098
Writedown of petroleum and natural gas properties (note 6)	-	10,418
Unrealized foreign exchange gain on US debt	(24,188)	(1,566)
Realized foreign exchange gain on US debt (note 8)	(7,161)	-
Premium on redemption of US debt (note 8)	11,950	-
	381,879	356,907
Earnings (loss) before income taxes	82,350	(59,584)
Income and other taxes (note 10)		
Large Corporations Tax and other	6,795	2,689
Future income tax expense (recovery)	40,660	(63,481)
	47,455	(60,792)
Net earnings from continuing operations	34,895	1,208
Net earnings (loss) from discontinued operations (note 5)	6,279	(57)
Net earnings	41,174	1,151
Retained earnings, beginning of period	295,013	355,912
Adjustment on disposition of assets to Paramount Energy Trust (note 4)	-	(6,923)
Dividends declared (note 4)	-	(51,000)
Purchase and cancellation of share capital (note 9)	(14,080)	-
Change in accounting policy (note 2)	-	(4,127)
Retained earnings, end of the year	$ 322,107	$ 295,013
Net earnings from continuing operations per common share		
- basic	$ 0.58	$ 0.02
- diluted	$ 0.57	$ 0.02
Net earnings (loss) from discontinued operations per common share		
- basic	$ 0.11	$ -
- diluted	$ 0.10	$ -
Net earnings per common share		
- basic	$ 0.69	$ 0.02
- diluted	$ 0.67	$ 0.02
Weighted average common shares outstanding (thousands)		
- basic	59,755	60,098
- diluted	61,026	60,472

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS of CASH FLOWS

Year Ended December 31 (thousands of dollars except per share amounts)	2004	2003 (restated - notes 2 and 5)
Operating activities		
Net earnings from continuing operations	$ 34,895	$ 1,208
Add (deduct)		
Depletion and depreciation	191,578	165,098
Writedown of petroleum and natural gas properties	-	10,418
(Gain) loss on sales of property, plant and equipment	(16,255)	3,640
Accretion of asset retirement obligations	6,920	4,044
Future income tax (recovery) expense	40,660	(63,481)
Amortization of other assets	1,277	161
Non-cash stock based compensation expense	41,195	1,214
Non-cash gain on financial instruments	(19,376)	-
Unrealized foreign exchange gain on US debt	(24,188)	(1,566)
Realized foreign exchange gain on US debt	(7,161)	-
Premium on redemption of US debt	11,950	-
Dry hole costs	24,676	36,600
Geological and geophysical costs	8,728	8,450
Cash flow from continuing operations	294,899	165,786
Cash flow from discontinued operations	667	1,490
Cash flow from operations	295,566	167,276
Decrease in deferred revenue	(3,959)	(3,845)
Asset retirement obligations expenditures	(1,214)	-
Increase in other assets	-	(161)
Change in non-cash operating working capital from continuing operations (note 12)	(27,320)	(33,582)
Change in non-cash operating working capital from discontinued operations	-	201
	263,073	129,889
Financing activities		
Bank loans - draws	431,951	42,933
Bank loans - repayments	(298,173)	(477,338)
Shareholder loan	-	(33,000)
Proceeds from US debt offering, net of issuance costs	162,917	221,447
Redemption of US debt	(105,686)	-
Premium on redemption of US debt	(8,864)	-
Realized foreign exchange gain on US debt	7,161	-
Capital stock - issued, net of issuance costs	115,043	10,317
Capital stock - purchased and cancelled	(19,401)	(705)
Discontinued operations	(11,301)	(190)
	273,647	(236,536)
Cash flow (used in) provided by operating and financing activities	536,720	(106,647)
Investing activities		
Property, plant and equipment expenditures	(315,698)	(224,229)
Petroleum and natural gas property acquisitions	(322,598)	(228)
Proceeds on sale of property, plant and equipment	61,939	317,792
Change in non-cash investing working capital (note 12)	27,349	14,828
Discontinued operations	12,288	(1,516)
Cash flow used in investing activities	(536,720)	106,647
Increase (decrease) in cash	-	-
Cash, beginning of the year	-	-
Cash, end of the year	$ -	$ -

See accompanying notes to consolidated financial statements.

NOTES to CONSOLIDATED FINANCIAL STATEMENTS

(all tabular amounts expressed in thousands of dollars)

1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Paramount Resources Ltd. ("Paramount" or the "Company") is an independent Canadian energy company involved in the exploration, development, production, processing, transportation and marketing of natural gas and oil. The Company's principal properties are located in Alberta, the Northwest Territories and British Columbia in Canada. The Company also has properties in Saskatchewan and offshore the East Coast in Canada, and in Montana and North Dakota in the United States. The consolidated financial statements are stated in Canadian dollars and have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP), which differ in some respects from GAAP in the United States. These differences are quantified in note 17.

The timely preparation of the financial statements in conformity with GAAP requires that Management make estimates and assumptions and use judgment regarding assets, liabilities, revenue and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results could differ from those estimates.

(A) PRINCIPLES OF CONSOLIDATION

The Consolidated Financial Statements include the accounts of Paramount Resources Ltd. and its subsidiaries, and are presented in accordance with Canadian generally accepted accounting principles.

Investments in jointly controlled companies, jointly controlled partnerships (collectively called "affiliates") and unincorporated joint ventures are accounted for using the proportionate consolidation method, whereby the Company's proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

Investments in companies and partnerships in which the Company does not have direct or joint control over the strategic operating, investing and financing decisions, but does have significant influence on them, are accounted for using the equity method.

(B) JOINT OPERATIONS

Certain of the Company's exploration, development and production activities related to petroleum and natural gas are conducted jointly with others. These consolidated financial statements reflect only the Company's proportionate interest in such activities.

(C) REVENUE RECOGNITION

Revenues associated with the sale of natural gas, crude oil, and natural gas liquids ("NGLs") owned by the Company are recognized when title passes from the Company to its customer.

Revenues from oil and natural gas production from properties in which the Company has an interest with other producers are recognized on the basis of the Company's net working interest.

(D) SHORT-TERM INVESTMENTS

Short-term investments are carried at the lower of cost and market value. Included in short-term investments are short-term deposits bearing interest between 2.15 percent to 2.23 percent, debentures and convertible debentures bearing interest between 6 percent to 8 percent and investments in the common shares and Trust units.

(E) PROPERTY, PLANT AND EQUIPMENT

COST

Property, plant and equipment are recorded at cost. The Company follows the successful efforts method of accounting for petroleum and natural gas operations. Under this method the Company capitalizes only those costs that result directly in the discovery of petroleum and natural gas reserves.

Exploratory well costs are capitalized pending further evaluation of whether economically recoverable reserves have been found of a sufficient quantity to justify completion of the find as a producing well. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. Exploratory wells in areas not requiring major capital expenditures are evaluated for economic viability within one year of well completion. This determination of the success of drilling results corresponds with the time period of reporting proved oil and gas reserves for the find. Exploratory wells

that discover economic reserves that are in areas where a major infrastructure capital expenditure (e.g., a pipeline) would be required before production could begin, or where the economic viability of that major capital expenditure depends upon the successful completion of further exploratory drilling work in the area, remain capitalized as long as the additional exploratory drilling work is under way or firmly planned. In these situations, the well is considered to have found economic reserves if recoverable reserves have been found of a sufficient quantity to justify completion of the find as a producing well, assuming that the major infrastructure capital expenditure had already been made. Once all additional exploratory drilling and testing work has been completed on projects requiring major infrastructure capital expenditures, the economic viability of the overall project is evaluated within one year of the last exploratory well completion. If considered to be economically viable, internal company approvals are then obtained to move the project into the development stage. Often, the ability to move the project into the development phase and record proved reserves is dependent on obtaining permits and government or co-venturer approvals, the timing of which is ultimately beyond the Company's control. Exploratory well costs remain suspended as long as the Company is actively pursuing such approvals and permits, and believes they will be obtained. Once all required approvals and permits have been obtained, the projects are moved into development stage, which corresponds with the time period of reporting proved oil and gas reserves for the find. For complex exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while the Company performs additional drilling work on the potential oil and gas field, or seeks government or co-venturer approval of development plans or environmental permitting.

Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized.

Exploration expenses, including geological and geophysical costs, lease rentals and exploratory dry hole costs, are charged to earnings as incurred. Leasehold acquisition costs, including costs of drilling and equipping successful wells, are capitalized. The net costs of unproductive exploratory wells, abandoned wells and surrendered leases are charged to earnings in the year of abandonment or surrender. Gains or losses are recognized on the disposition of property, plant and equipment.

DEPLETION AND DEPRECIATION

Capitalized costs of proved oil and gas properties are depleted using the unit of production method. For purposes of these calculations, production and reserves of natural gas are converted to barrels on an energy equivalent basis.

Successful exploratory wells and development costs are depleted over proved developed reserves while acquired resource properties with proved reserves are depleted over proved reserves. Acquisition costs of probable reserves are not depleted or amortized while under active evaluation for commercial reserves. Costs are transferred to depletable costs as proved reserves are recognized. At the date of acquisition, an evaluation period is determined after which any remaining probable reserve costs associated with producing fields are transferred to depletable costs.

Costs associated with significant development projects are not depleted until commercial production commences. Depreciation of production equipment, gas plants and gathering systems is provided on a straight-line basis over their estimated useful life varying from 12 years to 40 years. Depreciation of other equipment is provided on a declining balance method at rates varying from 4 percent to 30 percent.

IMPAIRMENT

Producing areas and significant unproved properties are assessed annually or as economic events dictate for potential impairment. Any impairment loss is the difference between the carrying value of the asset and its discounted net recoverable amount.

(F) ASSET RETIREMENT OBLIGATIONS

The Company recognizes the fair value of an asset retirement obligation in the period in which it is incurred or when a reasonable estimate of the fair value can be made. The asset retirement costs equal to the fair-value of the retirement obligations are capitalized as part of the cost of the related long-lived asset and allocated to expense on a basis consistent with depreciation and depletion. The liability associated with the asset retirement costs is subsequently adjusted for the passage of time which is recognized as accretion expense in the consolidated statement of earnings. The liability is also adjusted due to revisions in either the timing or the amount of the original estimated cash flows associated with the liability. Actual costs incurred upon settlement of the asset retirement obligations will reduce the asset retirement

liability to the extent of the liability recorded. Differences between the actual costs incurred upon settlement of the asset retirement obligations and the liability recorded are recognized in the Company's earnings in the period in which the settlement occurs.

(G) GOODWILL

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is not amortized and is assessed by the Company for impairment at least annually. Goodwill has been allocated to reporting units within the Company. Impairment is assessed based on a comparison of the fair value of the reporting units compared to the carrying value of the reporting units, including goodwill. Any excess of the carrying value of the reporting units, including goodwill, over and above its fair value is the impairment amount, and is charged to earnings in the period identified.

(H) FOREIGN CURRENCY TRANSLATION

The Company's foreign operations are considered integrated and are translated into Canadian dollars using the temporal method.

Monetary assets and liabilities denominated in US dollars are translated into Canadian dollars at exchange rates in effect at the balance sheet date. Other assets and liabilities are translated at the rates prevailing at the respective transaction dates. Revenues and expenses are translated at the average monthly rates prevailing during the year. Translation gains and losses are reflected in income when incurred.

(I) FINANCIAL INSTRUMENTS

The Company periodically utilizes derivative financial instrument contracts such as forwards, futures, swaps and options to manage its exposure to fluctuations in petroleum and natural gas prices, the Canadian/US dollar exchange rate and interest rates.

The Company's policy is to account for those derivative financial instruments in which management has formally documented its risk objectives and strategies for undertaking the hedged transaction as hedges. For these instruments, the Company has determined that the derivative financial instruments are effective as hedges, both at inception and over the term of the hedging relationship, as the term to maturity, the notional amount, the commodity price, exchange rate, and interest rate basis of the instruments, all match the terms of the transaction being hedged. The Company assesses the effectiveness of the derivatives on an ongoing basis to ensure that the derivatives entered into are highly effective in offsetting changes in fair values or cash flows of the hedged items. The fair values of derivative financial instruments designated as hedges are not reflected in the consolidated financial statements. Derivative financial instruments not formally designated as hedges are measured at fair value and recognized on the consolidated balance sheet with changes in the fair value recognized in earnings during the period.

(J) MEASUREMENT UNCERTAINTY

The amounts recorded for depletion and depreciation and impairment of petroleum and natural gas properties and equipment, and for asset retirement obligations are based on estimates of reserves, future costs, petroleum and natural gas prices and other relevant assumptions. By their nature, these estimates and those related to the future cash flows used to assess impairment are subject to measurement uncertainty, and the impact on the consolidated financial statements of future periods could be material.

(K) INCOME TAXES

The Company follows the liability method of accounting for income taxes. Under this method, future tax assets and liabilities are determined based on differences between financial reporting and income tax basis of assets and liabilities, and are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in net earnings in the period in which the change occurs.

(L) FLOW-THROUGH SHARES

Share capital includes flow-through shares issued pursuant to certain provisions of the Income Tax Act (Canada) (the "Act"). Under the Act, where the proceeds are used for eligible expenditures, the related income tax deductions may be renounced to subscribers.

As the eligible expenditures are renounced, share capital is reduced by an amount equal to the estimated future income taxes payable by the Company, and the estimated future income tax payable is recorded as an increase to the future income tax liability.

(M) STOCK OPTION PLAN

The Company has a stock-based compensation plan consisting of a stock option plan that is described in note 9.

Options granted under the Company's employee stock option plan are issued at the current market price on the day prior to issuance. The Company uses the intrinsic value method to account for its stock-based compensation. Applying the intrinsic value method to account for stock-based compensation, a liability for expected cash settlement under the stock-based compensation plan is accrued over the vesting period of the options, based on the difference between the exercise price of the options and the market price of the Company's common shares. The liability is revalued at the end of each reporting period to reflect changes in the market price of the Company's common shares and the net change is recognized in earnings. When options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When options are exercised for common shares, consideration paid by the option holders and the previously recognized liability associated with the options are recorded as share capital.

(N) AMORTIZATION OF OTHER ASSETS

Amortization of deferred items included in Other Assets is provided for where applicable, on a straight-line basis over their estimated useful life.

(O) PER COMMON SHARE AMOUNTS

The Company uses the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. This method assumes that proceeds received from the exercise of in-the-money stock options and other dilutive instruments are used to purchase common shares at the average market price during the period.

2. CHANGES IN ACCOUNTING POLICIES

ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2004, the Company retroactively adopted, with restatement, the Canadian Institute of Chartered Accountants ("CICA") recommendation on Asset Retirement Obligations, which requires liability recognition for the fair value of retirement obligations associated with long-lived assets. Prior to January 1, 2004, the estimated future dismantlement and site restoration costs of natural gas and crude oil assets were provided for using the unit-of-production method.

As a result of this change, net earnings for the year ended December 31, 2003 decreased by $1.5 million ($0.02 per share). The asset retirement obligations liability as at December 31, 2003 increased by $40.4 million, property, plant and equipment, net of accumulated depletion, increased by $31.1 million, and future income tax liability decreased $3.7 million. Opening 2003 retained earnings decreased by $4.1 million to reflect the cumulative impact of depletion expense and accretion expense, net of the previously recognized cumulative site restoration provision and net of related future income taxes on the asset retirement obligations, recorded retroactively.

FINANCIAL INSTRUMENTS

The Company periodically utilizes derivative financial instrument contracts such as forwards, futures, swaps and options to manage its exposure to fluctuations in petroleum and natural gas prices, the Canadian/US dollar exchange rate and interest rates. Emerging Issues Committee Abstract 128, "Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments" ("EIC 128") establishes accounting and reporting standards requiring that every derivative instrument that does not qualify for hedge accounting be recorded in the consolidated balance sheet as either an asset or liability measured at fair value. Accounting Guideline 13, Hedging Relationships, ("AcG 13"), which was effective for years beginning on or after July 1, 2003, establishes the need for companies to formally designate, document and assess the effectiveness of relationships that receive hedge accounting treatment.

Prior to January 1, 2004, Paramount had designated its derivative financial instruments as hedges. As at January 1, 2004, the Company had elected not to designate any of its financial instruments as hedges under AcG 13 and has fair-valued the derivatives and recognized the gains and losses on the consolidated balance sheet and statement of earnings. The impact

on the Company's consolidated financial statements at January 1, 2004, resulted in the recognition of financial instrument assets with a fair value of $3.3 million, a financial instrument liability of $1.8 million for a net deferred gain on financial instruments of $1.5 million (note 11).

TRANSPORTATION COSTS

Effective for fiscal years beginning on or after October 1, 2003, the CICA issued Handbook Section 1100 "Generally Accepted Accounting Principles", which defines the sources of GAAP that companies must use and effectively eliminates industry practice as a source of GAAP. In prior years, it had been industry practice for companies to net transportation charges against revenue rather than showing transportation as a separate expense on the income statement. Beginning January 1, 2004, the Company has recorded revenue gross of transportation charges and a transportation expense on the statement of earnings. Prior periods have been reclassified for comparative purposes. This adjustment has no impact on net income or cash flow.

STOCK-BASED COMPENSATION AND OTHER STOCK-BASED PAYMENTS

The Company has an Employee Incentive Stock Option plan (the "plan"). Prior to 2004, the Company applied the fair value method to account for its stock based compensation plan. During 2004, the Company reviewed its historical practices and determined that the Company has generally settled in cash when the option holder requested cash upon exercise of their options. Accordingly, in 2004, the Company has prospectively adopted the intrinsic value method to account for its stock-based compensation (see note 9).

3. ACQUISITION OF OIL AND GAS PROPERTIES

$185 MILLION ASSET ACQUISITION

On June 30, 2004, the Company completed an agreement to acquire oil and natural gas assets for $185.1 million, after adjustments. The assets acquired by the Company are located in the Kaybob area in central Alberta, in the Fort Liard area in the Northwest Territories and in northeast British Columbia. The properties acquired are adjacent to, or nearby, the Company's existing properties in Kaybob and Fort Liard. The Company has assigned the entire amount of the purchase price to property, plant and equipment and has recognized a $26.8 million asset retirement obligation liability related to those properties.

The following table summarizes the fair value of the net assets acquired:

Property, plant and equipment	$ 211,947
Less: Asset retirement obligations	26,847
	$ 185,100

$87 MILLION ASSET ACQUISITION

On August 16, 2004, Paramount completed the acquisition of assets in the Marten Creek area in Grande Prairie for $86.9 million, after adjustments. The asset retirement obligations associated with these assets is $2.1 million. In accounting for the acquisition, the Company recorded a future tax asset in the amount of $89.0 million.

4. DISPOSITION OF ASSETS TO PARAMOUNT ENERGY TRUST

During the first quarter of 2003, the Company completed the formation and structuring of Paramount Energy Trust (the "Trust") through the following transactions:

a) On February 3, 2003, Paramount transferred to the Trust natural gas properties in the Legend area of Northeast Alberta for net proceeds of $28 million and 9,907,767 units of the Trust.

b) On February 3, 2003, Paramount declared a dividend-in-kind of $51 million, consisting of an aggregate of 9,907,767 units of the Trust. The dividend was paid to shareholders of Paramount's common shares of record on the close of business on February 11, 2003.

c) On March 11, 2003, in conjunction with the closing of a rights offering by the Trust, Paramount disposed of additional natural gas properties in Northeast Alberta to Paramount Operating Trust for net proceeds of $167 million.

As the transfer of the Initial Assets and the Additional Assets (collectively the "Trust Assets") represented a related party transaction not in the normal course of operations involving two companies under common control, the transaction has been accounted for at the net book value of the Trust Assets as recorded in the Company. Details are as follows:

Natural gas properties	$ 244,433
Future income tax liability	4,070
Site restoration liability	(5,900)
Costs of disposition	10,430
Charge to retained earnings	(6,638)
Net proceeds on disposition	$ 246,395

In connection with the creation and financing of the Trust and the transfer of natural gas properties to the Trust, the Company incurred costs of approximately $10.4 million. These costs have been included as a cost of disposition.

During 2003, the Company disposed of a minor non-core property to the Trust. The related party transaction was accounted for at the net book value of the assets, with a charge to retained earnings of $0.3 million.

5. DISCONTINUED OPERATIONS

On July 27, 2004, Wilson Drilling Ltd. ("Wilson"), a private drilling company in which Paramount owns a 50 percent equity interest, closed the sale of its drilling assets for $32 million to a publicly traded Income Trust. The gross proceeds were $19.2 million cash with the balance in exchangeable shares. The exchangeable shares are valued at the fair market value of the purchasers' shares and can be redeemed for trust units in the Income Trust subject to customary securities laws and regulations. In connection with the closing of the sale, certain indebtedness related to these operations has been extinguished. For reporting purposes, the results of operations, property, plant and equipment, and the current and long-term debt have been presented as discontinued operations. Prior period financial statements have been reclassified to reflect this change.

On September 10, 2004, Paramount completed the disposition of its 99 percent interest in Shehtah Wilson Drilling Partnership for approximately $1.0 million. For reporting purposes, the drilling partnership has been accounted for as discontinued operations.

On December 13, 2004, Paramount completed the disposition of a building acquired as part of the Summit acquisition, for approximately $10.5 million, inclusive of the mortgage assumed by the purchaser of $6.4 million.

Selected financial information of the discontinued operations for the year ended December 31:

	Wilson Drilling Ltd.		Shehtah Wilson Drilling Partnership		Building		Total	
	2004	2003	**2004**	2003	**2004**	2003	**2004**	2003
Revenue								
Other Income	**$ 908**	$ 1,390	**$ 327**	$ 622	**$ -**	$ -	**$ 1,235**	$ 2,012
Expenses								
Interest	**250**	319	**-**	-	**367**	383	**617**	702
General and administrative	**642**	270	**384**	496	**(308)**	(1,133)	**718**	(367)
Depreciation	**655**	898	**6**	6	**278**	300	**939**	1,204
(Gain) loss on sale of property and equipment	**(6,659)**	20	**(27)**	-	**(2,569)**	-	**(9,255)**	20
	(5,112)	1,507	**363**	502	**(2,232)**	(450)	**(6,981)**	1,559
Net earnings (loss) before income tax	**6,020**	(117)	**(36)**	120	**2,232**	450	**8,216**	453
Large Corporation Tax and other	**1,857**	-	**-**	-	**(34)**	186	**1,823**	186
Future income tax expense	**94**	324	**-**	-	**20**	-	**114**	324
Net earnings (loss) from discontinued operations	**$ 4,069**	$ (441)	**$ (36)**	$ 120	**$ 2,246**	$ 264	**$ 6,279**	$ (57)

	Wilson Drilling Ltd. Dec-31 2004	Wilson Drilling Ltd. Dec-31 2003	Shehtah Wilson Drilling Partnership Dec-31 2004	Shehtah Wilson Drilling Partnership Dec-31 2003	Building Dec-31 2004	Building Dec-31 2003	Total Dec-31 2004	Total Dec-31 2003
Current Assets								
Accounts Receivable	$ -	$ -	$ -	$ 1,653	$ -	$ -	$ -	$ 1,653
Prepaid Expenses	-	-	-	27	-	-	-	27
Property, plant and equipment, net	-	3,234	-	62	-	8,097	-	11,393
Current Liabilities								
Accounts payable and accrued liabilities	-	-	-	1,005	-	-	-	1,005
Current portion of long-term debt	-	1,138	-	-	-	312	-	1,450
Long-term debt	$ -	$ 3,456	$ -	$ -	$ -	$ 6,418	$ -	$ 9,874

6. PROPERTY PLANT AND EQUIPMENT

	2004 Cost	2004 Accumulated Depletion and Depreciation	2003 Cost (restated - notes 2 and 5)	2003 Accumulated Depletion and Depreciation (restated - notes 2 and 5)
Petroleum and natural gas properties	**$ 1,351,950**	**$ 450,518**	$ 986,919	$ 307,156
Gas plants, gathering systems and production equipment	**548,838**	**127,724**	436,772	101,120
Other	**32,316**	**9,056**	20,448	9,949
Assets held for sale	**-**	**-**	14,865	3,472
	$ 1,933,104	**$ 587,298**	$ 1,459,004	$ 421,697
Net book value	**$ 1,345,806**		$ 1,037,307	

Capital costs associated with non-producing petroleum and natural gas properties totaling approximately $300 million (2003 – $209 million) are currently not subject to depletion.

For the year ended December 31, 2004, the Company expensed $24.7 million in dry hole costs (2003 - $36.6 million). A portion of the dry hole costs expensed related to prior year capital projects that were determined in the current year to have no future economic value.

For the year ended December 31, 2004, the Company recorded a provision of $ nil (2003 - $10.4 million) in respect of impairment of petroleum and natural gas properties.

7. ASSET RETIREMENT OBLIGATIONS

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligation associated with the retirement of the Company's oil and gas properties.

Year Ended December 31	2004	2003 (restated - notes 2 and 5)
Asset retirement obligation, beginning of year	$ 61,554	$ 53,625
Liabilities incurred	36,812	3,885
Liabilities settled	(3,800)	-
Accretion expense	6,920	4,044
Asset retirement obligation, end of year	$ 101,486	$ 61,554

The undiscounted asset retirement obligations at December 31, 2004 are $136.2 million (December 31, 2003 - $104.8 million). The Company's credit-adjusted risk-free rate is 7.875 percent. These obligations will be settled based on the useful life of the underlying assets, the majority of which are not expected to be paid for several years, or decades, in the future and will be funded from general company resources at the time of removal.

8. LONG-TERM DEBT

As at December 31, long-term debt was comprised of:

	2004	2003 (restated - notes 2 and 5)
7 7/8% US Senior Notes due 2010 (US$133.3 million)	$ 160,174	$ 226,887
8 7/8% US Senior Notes due 2014 (US$81.3 million)	97,662	-
Credit facility – current interest rate of 3.8% (2003 - 4.5%)	201,305	60,350
	$ 459,141	$ 287,237

SENIOR NOTES

The Company issued US$175 million of 7 7/8 percent Senior Notes due 2010 on October 27, 2003. Interest on the notes is payable semi-annually, beginning in 2004. The Company may redeem some or all of the notes at any time after November 1, 2007 at redemption prices ranging from 100 percent to 103.938 percent of the principal amount, plus accrued and unpaid interest to the redemption date, depending on the year in which the notes are redeemed. In addition, the Company may redeem up to 35 percent of the notes prior to November 1, 2006 at 107.875 percent of the principal amount, plus accrued interest to the redemption date, using the proceeds of certain equity offerings. The notes are unsecured and rank equally with all of the Company's existing and future senior unsecured indebtedness. The Company incurred $7.4 million of financing charges related to the issuance of the Senior Notes. The financing charges are capitalized to other assets and amortized straight line over the term of the notes.

On June 29, 2004, the Company issued US$125 million 8 7/8 percent Senior Notes due 2014. Interest on the notes is payable semi-annually, beginning in 2005. The Company may redeem some or all of the notes at any time after July 15, 2009, at redemption prices ranging from 100 percent to 104.438 percent of the principal amount, plus accrued and unpaid interest to the redemption date, depending on the year in which the notes are redeemed. In addition, the Company may redeem up to 35 percent of the notes prior to July 15, 2007, at 108.875 percent of the principal amount, plus accrued interest to the redemption date, using the proceeds of certain equity offerings. The notes are unsecured and rank equally with all the Company's existing and future senior unsecured indebtedness. The Company incurred $4.8 million of financing charges related to the issuance of the Senior Notes. The financing charges related to the issuance of the Senior Notes are capitalized to other assets and amortized straight line over the term of the notes.

On December 30, 2004, pursuant to Paramount's 7 7/8 percent and 8 7/8 percent Senior Notes, Paramount redeemed US$41.7 million aggregate principal amount of its 7 7/8 percent Senior Notes due 2010 and US$43.8 million aggregate principal amount of its 8 7/8 percent Senior Notes due 2014. The redemption price was US$1,078.75 per US$1,000 principal amount of the 7 7/8 percent Senior Notes and US$1,088.75 per US $1,000 principal amount of the 8 7/8 percent Senior Notes plus, in each case, accrued and unpaid interest on the amount being redeemed to the redemption date. The

premium paid on redemption of the notes of US$7.2 million was charged to earnings. The realized foreign exchange gain on redemption was $7.2 million. Other assets decreased by $3.1 million to reflect the reduction in deferred financing costs upon redemption of the Senior Notes.

CREDIT FACILITY

As at December 31, 2004, the Company had a $270 million committed revolving/non-revolving term facility with a syndicate of Canadian banks. Borrowings under the facility bear interest at the lender's prime rate, banker's acceptance, or LIBOR rate plus an applicable margin dependent on certain conditions. The revolving nature of the facility is due to expire on March 31, 2005. The Company has requested and received approval for an extension on the revolving credit facility of 364 days. Advances drawn on the facility are secured by a fixed charge over the assets of the Company.

In February 2005, the Company's borrowing capacity under this facility was increased to $330 million as a result of the Company's Senior Notes redemption on December 30, 2004, and an increase in the value of its oil and natural gas reserves.

The Company has letters of credit totaling $28.1 million (December 31, 2003 - $10.3 million) outstanding with a Canadian chartered bank. These letters of credit reduce the amount available under the Company's working capital facility.

9. SHARE CAPITAL

AUTHORIZED CAPITAL

The authorized capital of the Company is comprised of an unlimited number of non-voting preferred shares without nominal or par value, issuable in series, and an unlimited number of common shares without nominal or par value.

Common Shares	Number	Consideration
Balance December 31, 2002	**59,458,600**	$ 190,193
Stock options exercised during the year	**710,000**	10,317
Shares repurchased - at carrying value	**(74,000)**	(236)
Balance December 31, 2003	**60,094,600**	$ 200,274
Shares repurchased - at carrying value	**(1,629,500)**	(5,322)
Stock options exercised	**220,500**	3,057
Common shares issued, net of issuance costs	**2,500,000**	54,901
Flow through shares issued, net of issuance costs	**2,000,000**	57,981
Tax adjustment on share issuance costs and flow-through share renunciations	-	(7,959)
Balance December 31, 2004	**63,185,600**	**$ 302,932**

ISSUED CAPITAL

The Company instituted a Normal Course Issuer Bid to acquire a maximum of five percent of its issued and outstanding shares which commenced May 15, 2003 and expired May 14, 2004. Between January 1, 2004 and May 14, 2004, 1,629,500 shares were purchased pursuant to the plan at an average price of $11.91 per share. For the year ended December 31, 2004, $14.1 million has been charged to retained earnings related to the share repurchase price in excess of the carrying value of the shares.

On October 15, 2004, Paramount completed the private placement of 2,000,000 common shares issued on a "flow-through" basis at $29.50 per share. The gross proceeds of the issue were $59 million. As at December 31, 2004, the Company had made renunciations of $23.7 million.

On October 26, 2004, Paramount completed the issuance of 2,500,000 common shares at a price of $23.00 per share. The gross proceeds of the issue were $57.5 million.

Between January 1, 2005 and March 7, 2005, 101,050 stock options exercised for cash consideration of $1.8 million. Another 707,200 stock options were exercised for shares which will reduce the stock based compensation liability by approximately $10.4 million.

STOCK OPTION PLAN

The Company has an Employee Incentive Stock Option plan (the "plan"). Under the plan, stock options are granted at the current market price on the day prior to issuance. Participants in the plan, upon exercising their stock options, may request to receive either a cash payment equal to the difference between the exercise price and the market price of the Company's common shares or common shares issued from Treasury. Irrespective of the participant's request, the Company may choose to only issue common shares. Cash payments made in respect of the plan are charged to general and administrative expenses when incurred. Options granted vest over four years and have a four and a half year contractual life.

As at December 31, 2004, 5.0 million shares were reserved for issuance under the Company's Employee Incentive Stock Option Plan, of which 3.2 million options are outstanding, exercisable to May 31, 2009, at prices ranging from $8.91 to $26.29 per share.

Stock options	2004		2003	
	Average Grant Price	Options	Average Grant Price	Options
Balance, beginning of year	$ 9.64	3,632,000	$ 14.25	1,949,500
Granted	17.09	348,000	9.66	2,998,000
Exercised	9.97	(618,500)	14.29	(791,000)
Cancelled	9.09	(149,000)	10.30	(524,500)
Balance, end of year	$ 10.41	3,212,500	$ 9.64	3,632,000
Options exercisable, end of year	$ 10.26	1,282,875	$ 10.72	1,087,875

The formation of Paramount Energy Trust (note 4) resulted in the Company re-pricing stock options. 941,500 stock options issued in 2001, the majority of which were at exercise prices of $14.50 and $13.35 per option, were re-priced to exercise prices of $10.22 and $9.07 per option, respectively.

The following summarizes information about stock options outstanding at December 31, 2004:

Exercise Prices	Number	Outstanding Weighted Average Contractual Life	Weighted Average Exercise Price	Exercisable Number	Exercisable Weighted Average Exercise Price
$8.91-9.80	2,088,000	3	$ 9.02	561,375	$ 9.00
$10.01-12.02	820,500	1	11.04	721,500	11.25
$12.51-26.29	304,000	4	18.01	-	-
Total	3,212,500	2	$ 10.41	1,282,875	$ 10.26

During 2004, the Company paid $2.9 million (2003 – less than $0.1 million) related to stock options exercised for cash.

FAIR VALUES

In 2004, the Company prospectively adopted the intrinsic value method to account for its stock-based compensation. The Company recognized compensation costs related to stock options issued and outstanding of $41.2 million (2003 - $1.2 million).

Prior to 2004, the fair values of common share options granted were estimated as at the grant date using the Black-Scholes option pricing model. The weighted average fair value of the options granted during 2003 was $3.42, calculated using a risk-free rate of 5.8 percent, an estimated life of 4 years and an estimated volatility of 39 percent.

PER SHARE INFORMATION

Basic earnings per share are calculated based on a weighted average number of common shares of 59,755,480 (2003 – 60,098,447). There are no anti-dilutive options at December 31, 2004.

10. INCOME TAXES

The income tax provision differs from the expected income taxes obtained by applying the Canadian corporate tax rate to earning (loss) before taxes as follows:

	2004	2003
Corporate tax rate	**39.04%**	40.67%
Calculated income tax expense (recovery)	**$ 32,150**	$ (24,233)
Increase (decrease) resulting from:		
Non-deductible Crown charges, net of Alberta Royalty Tax Credit	**25,455**	21,991
Federal resource allowance	**(21,787)**	(17,124)
Federal and provincial income tax rate adjustment	**481**	(30,257)
Attributed Canadian Royalty Income recognized	**(1,469)**	(5,228)
Large Corporations Tax and other	**6,795**	2,875
Non-taxable portion of gain on sale of investments	**(4,301)**	-
Stock based compensation	**3,205**	-
Recognition of tax pools not previously recognized	**-**	(3,343)
Other	**6,926**	(5,473)
Income tax expense (recovery)	**$ 47,455**	$ (60,792)

COMPONENTS OF FUTURE INCOME TAXES

The net future tax liability comprises:	2004	2003
Differences between tax base and reported amounts of depreciable assets	**$ 215,583**	$ 227,697
Asset retirement obligations	**(34,281)**	(23,486)
Stock-based compensation liability	**(12,405)**	-
Other	**(2,517)**	2,473
	$ 166,380	$ 206,684

11. FINANCIAL INSTRUMENTS

As disclosed in note 2, on January 1, 2004, the fair value of all outstanding financial instruments that were no longer designated as accounting hedges, were recorded on the consolidated balance sheet with an offsetting net deferred gain. The net deferred gain is recognized into net earnings over the life of the associated contracts.

The changes in fair value associated with the financial instruments are recorded on the consolidated balance sheets with the associated unrealized gain or loss recorded in net earnings. The estimated fair value of all financial instruments is based on quoted prices or, in the absence of quoted prices, third party market indications and forecasts.

The following tables present a reconciliation of the change in the unrealized and realized gains and losses on financial instruments from January 1, 2004 to December 31, 2004.

December 31	2004
Financial instrument asset	**$ 21,564**
Financial instrument liability	**(2,188)**
Net financial instrument asset	**$ 19,376**

Year Ended December 31, 2004	Net Deferred Amounts on Transition	Mark-to Market Gain (Loss)	Total
Fair value of contracts, January 1, 2004	$ (1,450)	$ 1,450	$ -
Change in fair value of contracts recorded on transition, still outstanding at December 31, 2004	-	1,301	**1,301**
Amortization of the fair value of contracts as at December 31, 2004	(196)	-	**(196)**
Fair value of contracts entered into during the period	-	18,271	**18,271**
Unrealized gain (loss) on financial instruments	**$ (1,646)**	**$ 21,022**	**$ 19,376**
Realized loss on financial instruments for the year ended December 31, 2004			**(683)**
Net gain on financial instruments for the year ended December 31, 2004			**$ 18,693**

(A) INTEREST RATE CONTRACTS

On June 6, 2004, the Company entered into a fixed to floating interest rate swap. The fair value of this contract as at December 31, 2004, was a gain of $3.3 million.

Description of Swap Transaction	Maturity Date	Notional Amount	Indenture Interest	Swap to	Effective Rate
Swap of 7 7/8% US$ Senior Notes	November 1, 2010	US$175 million	US$ fixed	US$ floating	US$ LIBOR plus 320 Basis Points

(B) FOREIGN EXCHANGE CONTRACTS

The Company has entered into the following currency index swap transactions, fixing the exchange rate on receipts of US$1 million each month at CDN$1.4337, expiring December 31, 2005. The US$/CDN$ closing exchange rate was 1.2020 as at December 31, 2004 (December 31, 2003 – 1.2965).

Year of settlement	US dollars	Weighted average exchange rate
2005	12,000	1.4337

At January 1, 2004, the Company recorded a deferred gain on financial instruments of $3.3 million related to existing foreign exchange contracts. The fair value of these contracts at December 31, 2004, was a gain of $2.7 million. The change in fair value, a $0.6 million loss, and $1.6 million amortization of the deferred gain have been recorded in the consolidated statement of earnings.

During November 2004, the Company entered into a series of US$/CDN$ put/call options. The fair value of these contracts as at December 31, 2004 was a gain of $0.8 million.

Put/Call	Strike	Foreign Exchange Option Currencies	Notional - CDN$	Expiry Date
Put	1.2048	USD/CDN	$ 60,240,000	January 12, 2005
Call	1.1765	USD/CDN	$ 58,825,000	January 12, 2005
Put	1.1976	USD/CDN	$ 59,880,000	January 10, 2005
Call	1.1628	USD/CDN	$ 58,140,000	January 10, 2005

(C) COMMODITY PRICE CONTRACTS

At December 31, 2004, the Company has entered into financial forward contracts as follows:

	Amount	Price	Term
Sales Contracts			
NYMEX Fixed Price	10,000 MMbtu/d	US$ 6.41	November 2004 - March 2005
NYMEX Fixed Price	10,000 MMbtu/d	US$ 7.46	November 2004 - March 2005
NYMEX Fixed Price	10,000 MMbtu/d	US$ 7.95	November 2004 - March 2005
AECO Fixed Price	20,000 GJ/d	$ 7.90	November 2004 - March 2005
AECO Fixed Price	20,000 GJ/d	$ 8.03	November 2004 - March 2005
AECO Fixed Price	20,000 GJ/d	$ 7.60	November 2004 - March 2005
NYMEX Call Option	20,000 MMbtu/d	US$ 10.00 Strike	December 2004 - March 2005
AECO Fixed Price	20,000 GJ/d	$ 6.28	April 2005 - June 2005
AECO Fixed Price	20,000 GJ/d	$ 6.30	April 2005 - June 2005
AECO Fixed Price	20,000 GJ/d	$ 6.80	April 2005 - June 2005
Purchase Contracts			
AECO Fixed Price	20,000 GJ/d	$ 6.76	November 2004 - March 2005

The fair values of these contracts as at December 31, 2004 was a $14.2 million gain.

At January 1, 2004, the Company recorded a deferred loss on financial instruments of $1.8 million related to existing forward commodity price contracts. The deferred loss has been fully amortized as at December 31, 2004.

(D) FAIR VALUES OF FINANCIAL ASSETS AND LIABILITIES

Borrowings under bank credit facilities and the issuance of commercial paper are for short periods and are market rate based, thus, carrying values approximate fair value. Fair values for derivative instruments are determined based on the estimated cash payment or receipt necessary to settle the contract at year-end. Cash payments or receipts are based on discounted cash flow analysis using current market rates and prices available to the Company.

(E) CREDIT RISK

The Company is exposed to credit risk from financial instruments to the extent of non-performance by third parties, and non-performance by counterparties to swap agreements. The Company minimizes credit risk associated with possible non-performance by financial instrument counterparties by entering into contracts with only highly rated counterparties and controls third party credit risk with credit approvals, limits on exposures to any one counterparty, and monitoring procedures. The Company sells production to a variety of purchasers under normal industry sale and payment terms. The Company's accounts receivable are with customers and joint venture partners in the petroleum and natural gas industry and are subject to normal credit risk.

(F) INTEREST RATE RISK

The Company is exposed to interest rate risk to the extent that changes in market interest rates will impact the Company's debts that have a floating interest rate.

12. CHANGE IN NON-CASH WORKING CAPITAL

	2004	2003
Change in non-cash working capital:		
Short-term investments	$ (10,532)	$ (283)
Accounts receivable	(25,480)	6,859
Prepaid expenses	(978)	1,829
Accounts payable and accrued liabilities	37,019	(26,958)
Discontinued operations	-	(201)
	29	(18,754)
Operating activities	(27,320)	(33,582)
Investing activities	27,349	14,828
	$ 29	$ (18,754)

Certain changes in non-cash working capital which were incurred as a result of asset dispositions during the year have been excluded from the above amounts.

Amounts paid during the year related to interest and Large Corporations and other taxes were as follows:

	2004	2003
Interest paid	$ 18,951	$ 17,497
Large Corporations and other taxes paid, including settlements	$ 31,021	$ 2,395

13. RELATED PARTY TRANSACTIONS

DISPOSITION OF ASSETS TO PARAMOUNT ENERGY TRUST

On December 13, 2004, the Company completed the disposition of a building to Paramount Energy Trust. The transaction has been recorded at the exchange amount. The Company received proceeds of $10.5 million, inclusive of the mortgage assumed by the purchaser of $6.4 million.

In the first quarter of 2003, the Company sold certain natural gas assets in Northeast Alberta to the Trust, a related party. The transaction (see note 4), was accounted for at the net book value of the assets as recorded in the Company.

14. CONTINGENCIES AND COMMITMENTS

CONTINGENCIES

The Company is party to various legal claims associated with the ordinary conduct of business. The Company does not anticipate that these claims will have a material impact on the Company's financial position.

The Company indemnifies its directors and officers against any and all claims or losses reasonably incurred in the performance of their service to the Company to the extent permitted by law. The Company has acquired and maintains liability insurance for its directors and officers.

COMMITMENTS

As at December 31, 2004, the Company has the following pipeline transportation commitments:

Year	Commitment
2005	$ 22,015
2006	21,252
2007	21,252
2008	21,252
2009	20,823
Thereafter	130,611
	$ 237,205

At December 31, 2004, the Company has entered into the following physical delivery natural gas contracts:

	Amount	Price	Term
Sales Contracts			
Station 2 Fixed Price	8,000 GJ/d	$ 7.99	November 2004 - March 2005
Station 2 Fixed Price	12,000 GJ/d	$ 8.00	November 2004 - March 2005

15. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the current year's financial statement presentation.

16. SUBSEQUENT EVENTS

TRUST SPINOUT

On September 27, 2004, the Board of Directors of Paramount authorized management of Paramount to undertake an examination of possible corporate restructuring alternatives available to Paramount to increase shareholder value, including but not limited to: maintaining the status quo and continuing Paramount's strategic direction as an independent oil and natural gas exploration and development company, and reorganizing Paramount, either in whole or in part, into an energy trust.

On December 13, 2004, Paramount announced that its board of directors had unanimously approved a proposed reorganization which would result in Paramount's shareholders receiving in exchange for their Common Shares, one New Common Share of Paramount and one Trust Unit of the Trust, Trilogy Energy Trust ("Trilogy").

Trilogy will indirectly own certain of Paramount's existing assets. The assets intended to become indirectly owned by Trilogy, referred to as the "Spinout Assets," are located in the Kaybob and Marten Creek areas of Alberta.

In order to implement any proposed reorganization of Paramount, the Company required the consent of the majority holders of each of its 2010 Notes in the aggregate principal amount of US$175 million and its 2014 Notes in the aggregate principal amount of US $125 million. Consent from note holders was obtained on February 7, 2005.

A special meeting of securityholders required for approval of the spinout transaction has been scheduled on March 28, 2005. The Trust Spinout is to be effected through an arrangement under the Business Corporations Act (Alberta) and Paramount obtained an interim order from the Court of Queen's Bench of Alberta regarding the meeting on February 28, 2005.

NOTES OFFERING

On February 7, 2005, Paramount completed the Notes Offer, as amended, issuing US$213,593,000 principal amount of 2013 Notes and paying aggregate cash consideration of approximately US$36.2 million in exchange for approximately 99.31 percent of the outstanding 2010 Notes and 100 percent of the outstanding 2014 Notes. As a result, US$913,000 principal amount of the 2010 Notes and no 2014 Notes remain outstanding.

The 2013 Notes bear interest at a rate of 8 1/2 percent per year and mature on January 31, 2013. The 2013 Notes will be secured by approximately 80 percent of the Trust Units that will be owned by Paramount following the completion of the Trust Spinout; however, Paramount may sell such Trust Units provided it makes an offer to the holders of the 2013 Notes to purchase 2013 Notes with the next proceeds of any sales at par plus a redemption premium of up to 4 1/4 percent depending on when the offer is made. The 2013 Notes cannot be redeemed with proceeds of equity offerings, but Paramount may, at its option, redeem all or part of the 2013 Notes after January 31, 2007 at par plus a redemption premium up to 4 1/4 percent depending on when the notes are redeemed. If holders of a majority in aggregate principal amount of the 2013 Notes provide notice on September 30, 2005 that they elect to increase the interest rate on the 2013 Notes to 10 1/2 percent per year, Paramount may, at its option, at any time on or prior to January 31, 2006, redeem all of the 2013 Notes at par.

GAS MARKETING LIMITED PARTNERSHIP

Paramount closed a transaction in March 2005 whereby it acquired an indirect 25 percent ownership interest in a gas marketing limited partnership for US$5 million. In conjunction with the acquisition of the ownership interest, Paramount will make available for delivery an average of 150 million GJ/d of natural gas over a five year term, to be marketed on Paramount's behalf by the gas marketing limited partnership.

17. RECONCILIATION OF FINANCIAL STATEMENTS TO UNITED STATES GENERALLY ACCEPTED PRINCIPLES

The consolidated financial statements have been prepared in accordance with Canadian GAAP. Any differences in accounting principles as they pertain to the accompanying financial statements are not material except as described below. The application of US GAAP would have the following effects on the Company's historical net earnings (loss) as reported:

Year ended December 31	2004	2003 (restated - notes 2 and 5)
Net earnings for the year as reported	**$ 41,174**	$ 1,151
Adjustments, net of tax		
Forward foreign exchange contracts and other financial instruments (a)	**(1,053)**	3,411
Impairments and related change in depletion (c)	**5,385**	11,546
General and administrative (i)	**-**	703
Short-term investments (f)	**929**	428
Future income taxes (b)	**(5,633)**	-
Earnings from discontinued operations (e)	**-**	(8,593)
Earnings before discontinued operations and change in accounting policy	**$ 40,802**	$ 8,646
Earnings from discontinued operations (e)	**-**	8,593
Change in accounting policy - Asset Retirement Obligation (d)	**-**	(4,127)
Net earnings for the year - US GAAP	**$ 40,802**	$ 13,112
Net earnings per common share before discontinued operations and change in accounting policy - US GAAP		
Basic	**$ 0.68**	$ 0.14
Diluted	**$ 0.67**	$ 0.14
Net earnings per common share - US GAAP		
Basic	**$ 0.68**	$ 0.22
Diluted	**$ 0.67**	$ 0.22

The application of US GAAP would have the following effect on the balance sheet at December 31:

	2004		2003	
	As Reported	**US GAAP**	As Reported (restated - notes 2 and 5)	US GAAP
Assets				
Short-term investments (f)	**$ 24,983**	**$ 27,149**	$ 16,551	$ 17,265
Financial instrument assets (a)	**21,564**	**18,271**	-	-
Property, plant and equipment (c)(d)	**1,345,806**	**1,350,286**	1,037,307	1,033,373
Liabilities				
Accounts payable and accrued liabilities (b)	**147,508**	**152,893**	109,334	109,334
Deferred hedging loss (a)	**-**	**-**	-	1,726
Financial instrument liability (a)	**2,188**	**542**	-	-
Deferred revenue (a)	**-**	**-**	3,959	-
Future income taxes (a)(b)(c)(f)	**166,380**	**167,587**	206,684	206,570
Shareholders' equity				
Common shares (b)	**302,932**	**303,180**	200,274	200,274
Retained earnings	**$ 322,107**	**$ 324,253**	$ 295,013	$ 298,295

(A) FORWARD FOREIGN EXCHANGE CONTRACTS AND OTHER FINANCIAL INSTRUMENTS

Prior to January 1, 2004, Paramount had designated, for Canadian GAAP purposes, its derivative financial instruments as hedges of anticipated revenue and expenses. In accordance with Canadian GAAP, payments or receipts on these contracts were recognized in income concurrently with the hedged transaction. Accordingly, the fair value of contracts deemed to be hedges was not previously reflected in the balance sheet, and changes in fair value were not reflected in earnings. As disclosed in note 2 of the consolidated financial statements as at and for the year ended December 31, 2004, effective January 1, 2004, the Company has elected not to designate any of its financial instruments as hedges for Canadian GAAP purposes, thus eliminating this US/Canadian GAAP difference in future periods.

For US purposes, the Company has adopted Statement of Financial Accounting Standards ("SFAS") No. 133, as amended, "Accounting for Derivative Instruments and Hedging Activities". With the adoption of this standard, all derivative instruments are recognized on the balance sheet at fair value. The statement requires that changes in the derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

Under US GAAP for the year ended December 31, 2004, the deferred financial instrument asset of $3.3 million and the deferred financial instrument liability of $1.8 million described in note 2 of the consolidated financial statements as at December 31, 2004 would not be recorded for US GAAP purposes. Amortization of the deferred financial instrument asset and liability would be recognized in earnings under Canadian GAAP. The remaining unamortized amount of $1.6 million (net of tax - $1.1 million) has been reflected as a retained earnings adjustment as this has been reflected in earnings in prior years US GAAP reconciliations.

Under US GAAP for the year ended December 31, 2004, an additional expense of $1.6 million (net of tax - $1.1 million) would have been recorded to adjust for the deferred financial instruments assets and liabilities amortization.

Under US GAAP for the year ended December 31, 2003, additional income of $5.7 million (net of tax - $3.4 million) would have been recorded.

(B) FUTURE INCOME TAXES

The Canadian liability method of accounting for income taxes is similar to the United States Statement of Financial Accounting Standard No. 109 "Accounting for Income Taxes", which requires the recognition of future tax assets and liabilities for the expected future tax consequences of events that have been recognized in the Company's financial statements or tax returns. Pursuant to US GAAP, enacted tax rates are used to calculate future taxes, whereas Canadian GAAP uses substantively enacted rates. For the years ended December 31, 2004 and 2003, this difference did not impact the Company's financial position or results of operations except for the Company's accounting for a flow-through share issuance in October 2004. For Canadian GAAP, upon renunciation of tax pools, an adjustment is made to share capital and future income tax liabilities. Under SFAS 109, the proceeds from the issuance of flow through shares should be allocated between the offering of shares and the sale of tax benefits. The allocation is made based on the difference between the quoted price of the existing shares and the amount the investor pays for the shares. A liability is recognized for this difference. The liability is reversed when tax benefits are renounced and a deferred tax liability is recognized at the time. Income tax expense is the difference between the amount of the future tax liability and the liability recognized on issuance. As at and for the year ended December 31, 2004, share capital would increase by $0.2 million, accounts payable and accrued liabilities would increase $5.4 million, and future income tax expense would increase $5.6 million.

(C) PROPERTY, PLANT AND EQUIPMENT

Under both US and Canadian GAAP, property, plant and equipment must be assessed for potential impairments. Under US GAAP, if the sum of the expected future cash flows (undiscounted and without interest charges) is less than the carrying amount of the asset, then an impairment loss (the amount by which the carrying amount of the asset exceeds the fair value of the asset) should be recognized. Fair value is calculated as the present value of estimated expected future cash flows. Prior to January 1, 2004, under Canadian GAAP, the impairment loss was the difference between the carrying value of the asset and its net recoverable amount (undiscounted). Effective January 1, 2004, the CICA implemented a new pronouncement on impairment of long-lived assets, which eliminated the US/Canadian GAAP difference going forward. For the year ended December 31, 2004, no impairment change would be recorded and a reduction in depletion expense of $8.4 million (net of tax - $5.4 million) would be recorded due to impairment charges recorded in fiscal 2002 and 2001.

For the year ended December 31, 2003, no impairment charge would be recorded and a reduction in depletion expense of $19.2 million (net of tax - $11.5 million) would be recorded due to impairment charges recorded in fiscal 2002 and 2001 under US GAAP. The resulting differences in recorded carrying values of impaired assets result in further differences in depreciation, depletion and amortization expense in subsequent years.

SUSPENDED WELLS

In September 2004, the EITF discussed Issue No. 04-9, "Accounting for Suspended Well Costs," as it relates to SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." SFAS No. 19 requires that the costs of exploratory wells be capitalized, or "suspended," on the balance sheet, pending a determination of whether potentially economic oil and gas reserves have been discovered. The discussion centered on whether certain circumstances would permit the continued capitalization of the costs for an exploratory well beyond one year, in the absence of plans for another exploratory well. The EITF removed the issue from its agenda, and requested that the FASB consider an amendment to SFAS No. 19 to clarify when it is permissible to continue to capitalize exploratory well costs beyond one year if (a) the well had found a sufficient quantity of reserves to justify its completion as a producing well, assuming the required capital expenditures would be made, and (b) the company was making sufficient progress assessing the reserves and the economic and operating viability of the project. In February 2005, the FASB posted FASB Staff Position (FSP) FAS No. 19-a, "Accounting for Suspended Well Costs," on its Web site for comment. The proposed FSP provides for continued capitalization past one year if a company is making sufficient progress on assessing the reserves and the economic and operating viability of the project. The proposed FSP also provides disclosure requirements about capitalized exploratory well costs. We estimate that if the proposed FSP were adopted prospectively on January 1, 2003, net income would not have changed in 2004 or 2003. We believe that the adoption of the FSP as proposed would not result in the write-off of any well suspended as of December 31, 2004. We plan to continue to monitor the deliberations of the FASB on this issue.

The following table reflects the net changes in suspended exploratory well costs during 2004 and 2003.

(millions of dollars)	2004	2003
Beginning balance at January 1	$ 46	$ 99
Additions pending the determination of proved reserves	110	15
Reclassifications to proved properties	(24)	(18)
Charged to dry hole expense	(14)	(23)
Wells sold during the period	-	(27)
Ending balance at December 31	$ 118	$ 46

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed and the number of wells for which exploratory well costs have been capitalized for a period greater than one year since the completion of drilling.

(millions of dollars)	2004	2003
Capitalized exploratory costs that have been capitalized for a period of one year or less	$ 86	$ 19
Capitalized exploratory costs that have been capitalized for a period of greater that one year	32	27
Balance at December 31	$ 118	$ 46
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	23	29

Included in total suspended well costs at year-end 2004 were 23 wells totaling $32 million related to areas where major capital expenditures and further exploratory drilling is required to classify the reserves as proved. These costs were suspended between 1999 and 2003. At December 31, 2004, $12 million of the costs related to Colville Lake in the Northwest Territories. The commerciality of the gas is being evaluated in conjunction with the upcoming drilling program and the completion of the Mackenzie Valley Gas Pipeline. The remaining $20 million relate to projects where infrastructure decisions are dependent on environmental permitting and production capacity, or where we are continuing to assess reserves and their potential development. At December 31, 2004, we did not have any amounts suspended that were associated with areas not requiring major capital expenditures before production could begin, where more than one year had elapsed since the completion of drilling.

(D) ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2004, the Company has retroactively adopted, with restatement, the CICA recommendations on Asset Retirement Obligations. For US GAAP purposes, the Company has adopted SFAS No. 143, "Accounting for Asset Retirement Obligations", effective January 1, 2003. For US GAAP, the cumulative impact upon adoption of SFAS No. 143 for the year ended December 31, 2003, is a $6.9 million (net of tax - $4.1 million) charge to earnings (loss) or $0.07 per basic and diluted common share. For Canadian GAAP purposes, upon adoption on January 1, 2004, the retroactive effect of this pronouncement on prior years was reflected in opening retained earnings for the earliest period presented.

(E) DISCONTINUED OPERATIONS

Under US GAAP, the transaction resulting in the disposal of the Trust Assets to Paramount Energy Trust as described in note 4 of the consolidated financial statements for the year-ended December 31, 2003 would be accounted for as discontinued operations as the applicable criteria set out in SFAS 144, "Accounting for Impairment or Disposal of Long-Lived Assets" had been met. Accordingly, the carrying value of the Trust Assets is separately presented in the consolidated balance sheet. Net income from discontinued operations for the year ended December 31, 2003 would have been $12.9 million (net of tax - $8.6 million), or $0.14 per basic and diluted common share.

(F) SHORT-TERM INVESTMENTS

Under US GAAP, equity securities that are bought and sold in the short term are classified as trading securities. Unrealized holding gains and losses related to trading securities are included in earnings as incurred. Under Canadian GAAP, these gains and losses are not recognized in earnings until the security is sold. As at December 31, 2004, the Company had unrealized holding gains of $2.2 million (net of tax - $1.4 million). As at December 31, 2003, the Company had unrealized holding gains of $0.7 million (net of tax - $0.4 million).

(G) OTHER COMPREHENSIVE INCOME

Under US GAAP, certain items such as the unrealized gain or loss on derivative instrument contracts designated and effective as cash flow hedges are included in other comprehensive income. In these financial statements, there are no comprehensive income items other than net earnings.

(H) STATEMENTS OF CASH FLOW

The application of US GAAP would change the amounts as reported under Canadian GAAP for cash flows provided by (used in) operating, investing or financing activities. For US GAAP, dry hole costs of $24.7 million (2003 - $36.6 million) are not added back in calculating cash flow from operations. For Canadian GAAP, the consolidated statements of cash flow include, under investing activities, changes in working capital for items not affecting cash, such as accounts payable related to the non-cash elements of property and equipment. For US GAAP, for the year ended December 31, 2004, there would be a reduction of $27.3 million (2003 – reduction of $14.8 million). The presentation of cash flow from operations is a non US GAAP terminology.

(I) STOCK-BASED COMPENSATION

The Company has granted stock options to selected employees, directors and officers. For US GAAP purposes, SFAS 123, "Accounting for Stock-Based Compensation", requires that an enterprise recognize, or at its option, disclose the impact of the fair value of stock options and other forms of stock-based compensation cost.

The following table summarizes the pro forma effect on earnings had the Company recorded the fair value of options granted:

Year ended December 31		2003
Net earnings for the period – US GAAP	$	13,112
Stock-based compensation expense determined under the fair value based method for all awards, net of related tax effects		(703)
Pro forma net earnings – US GAAP	$	12,409
Net earnings per common share		
Basic		
- as reported	$	0.22
- pro forma	$	0.21
Diluted		
- as reported	$	0.22
- pro forma	$	0.21

Under APB Opinion 25, the re-pricing of outstanding stock options under a fixed price stock option plan results in these options being accounted for as variable price options from the date of the modification until they are exercised, forfeited or expire. For the year ended December 31, 2004, there would be no impact as the Company has prospectively applied the intrinsic value method to account for its stock based compensation. For the year ended December 31, 2003, an additional income of $0.7 million would have been recorded as general and administrative expense related to the re-pricing of outstanding stock options and for the year ended December 31, 2003, $1.2 million of general and administrative expenses related to stock options under Canadian GAAP would be reversed as the Company has chosen not to fair value account for its options using the fair value method under SFAS 123.

(J) BUY/SELL ARRANGEMENTS

For US GAAP, buy/sell arrangements are reported on a gross basis. For the year ended December 31, 2004, the Company had sales of $22.2 million (2003 - $57.5 million) and purchases of $22.0 million (2003 - $63.1 million), related to buy/sell arrangements. The net gain of $0.2 million (2003 - $5.6 million loss) has been reflected in revenue for Canadian GAAP purposes

CORPORATE INFORMATION

OFFICERS

C. H. Riddell
Chairman of the Board and
Chief Executive Officer

B. K. Lee
Chief Financial Officer

J. H. T. Riddell
President and Chief Operating Officer

C. E. Morin
Corporate Secretary

L. M. Doyle
Corporate Operating Officer

C. G. Folden
Corporate Operating Officer

J. S. McDougall
Corporate Operating Officer

G. W. P. McMillan
Corporate Operating Officer

J. B. Williams
Corporate Operating Officer

L. A. Friesen
Assistant Corporate Secretary

DIRECTORS

C. H. Riddell(3)
Chairman of the Board and
Chief Executive Officer
Paramount Resources Ltd.
Calgary, Alberta

J. H. T. Riddell
President and
Chief Operating Officer
Paramount Resources Ltd.
Calgary, Alberta

J. C. Gorman(1) (4)
Retired
Calgary, Alberta

D. Jungé, C.F.A(4)
Chairman of the Board
Pitcairn Financial Group
Jenkintown, Pennsylvania
Calgary, Alberta

D. M. Knott
General Partner
Knott Partners, L.P.
Syosset, New York
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W. B. MacInnes, Q.C.(1) (2) (3) (4)
Retired
Calgary, Alberta

V. S. A. Riddell
Business Executive
Calgary, Alberta

S. L. Riddell Rose
President and
Chief Operating Officer
Paramount Energy Trust
Calgary, Alberta

J. B. Roy(1) (2) (3) (4)
Independent Businessman
Calgary, Alberta

A. S. Thomson(1) (4)
President
Touche, Thomson & Yeoman
Investment Consultants Ltd.
Calgary, Alberta

B. M. Wylie(2)
Business Executive
Calgary, Alberta

(1) Member of Audit Committee
(2) Member of Environmental, Health and Safety Committee
(3) Member of Compensation Committee
(4) Member of Corporate Governance Committee

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Calgary, Alberta

Canadian Imperial Bank of Commerce
Calgary, Alberta

The Bank of Nova Scotia
Calgary, Alberta

UBS AG Canada Branch
Toronto, Ontario

REGISTRAR AND TRANSFER AGENT

Computershare Investor Services Canada
Calgary, Alberta
Toronto, Ontario

STOCK EXCHANGE LISTING

The Toronto Stock Exchange
('POU')

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MAJOR PRODUCING PROPERTIES

The following table summarizes average production volumes from Paramount's major producing properties, for each of the last five fiscal years

Natural Gas (MMcf/d)	2004	2003	2002	2001	2000
Kaybob	**96.4**	79.5	87.5	65.3	63.7
Grande Prairie	**26.8**	12.4	7.0	3.1	–
Northwest Alberta	**20.2**	22.3	30.4	29.2	26.1
Liard – Northeast BC/NWT	**16.2**	11.6	12.3	9.3	5.4
Southern	**10.8**	9.5	5.4		–
Northeast Alberta	**1.6**	16.2	96.9	108.7	119.0
Other	**1.1**	1.3	1.9	9.4	5.8
Total	**173.1**	152.8	241.4	225.0	220.0

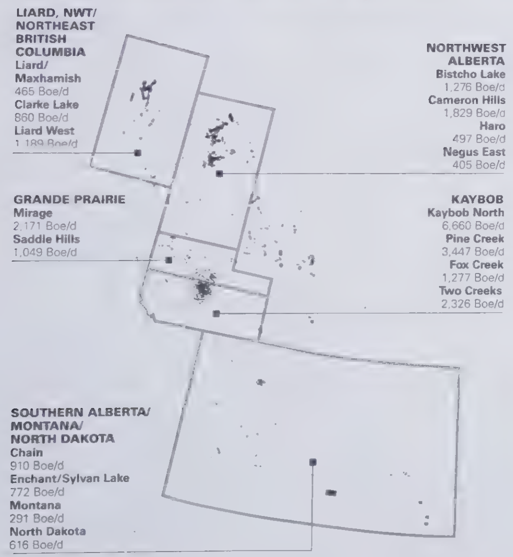
Crude Oil and Liquids (Bbl/d)	2004	2003	2002	2001	2000
Kaybob	**4,091**	2,451	2,291	1,855	1,258
Grande Prairie	**585**	1,767	1,353	–	–
Northwest Alberta	**797**	448	35	–	–
Liard - Northeast BC/NWT	**12**	9	15	21	95
Southern	**1,798**	2,457	1,732	130	218
Other	**14**	37	237	159	–
Total	**7,297**	7,169	5,663	2,165	1,571

Total Production (Boe/d @ 6:1)	2004	2003	2002	2001	2000
Kaybob	**20,157**	15,704	[illegible]	12,736	11,875
Grande Prairie	**5,053**	3,831	2,520	517	–
Northwest Alberta	**4,165**	4,165	5,102	4,867	4,350
Liard - Northeast BC/NWT	**2,710**	1,942	2,065	1,571	995
Southern	**3,596**	4,048	2,632	130	218
Northeast Alberta	**252**	2,700	16,150	18,117	19,833
Other	**217**	240	555	1,725	[illegible]
Total	**36,150**	32,630	45,898	39,665	38,238

CAPITAL EXPENDITURES

($ millions)	2004	2003
Drilling	**$ 184.5**	$ 123.4
Seismic	**8.7**	8.5
Facilities and equipment	**85.2**	69.6
Land acquisitions	**37.9**	22.3
Property acquisitions	**322.6**	0.9
Other	**1.9**	1.9
	640.8	226.6
Property dispositions	**(61.8)**	(371.6)
Net capital expenditures	**$ 579.0**	$ (145.0)

CORE PRODUCING PROPERTIES



BALANCE SHEET INFORMATION

As at December 31 ($ millions)	2004	2003	Change (%)
Assets			
Current assets	**$ 158**	$ 101	56
Property, plant and equipment, net	**1,346**	1,037	30
Other assets	**39**	39	2
	$ 1,543	$ 1,177	31
Liabilities and Shareholders' Equity			
Current liabilities	**$ 150**	112	34
Long-term debt	**459**	287	60
Asset retirement obligations	**102**	62	65
Deferred revenue	–	4	(100)
Stock based compensation liability	**41**	–	–
Future income taxes	**166**	207	(19)
Liabilities of discontinued operations	–	10	(100)
Shareholders' equity	**625**	496	26
	$ 1,543	$ 1,177	31

NET ASSET VALUE PER COMMON SHARE

As at December 31, 2004 ($ millions except per share amount)	
Discount rate	10%
Present value of reserves [1,2]	$ 1659.3
Market value of short-term investments	27.1
Fair market value of undeveloped land	185.4
Other assets [3]	184.5
Subtotal	2056.3
Working capital deficiency [4]	(170)
Debt	(459.1)
Net asset value	$ 1580.2
Net asset value per common share [5]	$ 25.01

(1) Proved plus probable discounted at 10 percent, includes benefit of ARTC with no allowance for income tax

(2) Based on Forecast Prices and Costs Assumptions

(3) Includes seismic projects under evaluation and other assets (all at cost)

(4) Excludes short-term investments

(5) Based on outstanding common shares of 63 185 600 at December 31, 2004

CAPITAL STRUCTURE

The following table outlines Paramount's capital structure since 2000

($ thousands)	2004	2003	2002	2001	2000
Debt	**$ 459,141**	$ 287,237	$ 539,270	$ 316,600	$ 315,000
Common share equity	**302,932**	200,274	190,193	189,320	189,320
Retained earnings	**322,107**	295,013	355,912	346,064	228,934
	$ 1,084,180	$ 782,524	$ 1,085,375	$ 851,984	$ 733,254

NET DEBT

At December 31 ($ thousands)	2004	2003
Current assets [1]	**$ 157,650**	$ 99,516
Current liabilities [1]	**149,696**	109,334
Working capital (surplus) deficiency	**(7,954)**	9,818
Debt [1]	**459,141**	287,237
Net debt	**$ 451,187**	$ 297,055

(1) Excludes discontinued operations

ESTIMATED FUTURE PRE-TAX CASH FLOW

	Reserves Before Royalty		Present Value of Estimated Pre-tax Cash Flow Discounted at (millions of dollars)	
	Gas (Bcf)	Oil/liquids (MBbl)	10%	15%
Proved	347.2	15,042	1,156	1,022
Probable	221.4	5,419	503	398
Total	568.6	20,461	1,659	1,420

The discounted net present values of the estimated pre-tax cash flow expected during the economic life of all reserves are based on estimates using escalating price assumptions at rates of 10 percent and 15 percent per annum compounded annually They are calculated prior to the consideration of income taxes but include ARTC, and are not to be construed as representing the fair market value of properties The fair market value of the properties and such net present values will depend upon the subjective considerations inherent to each property

KEY RATIOS

The following key ratios to "fundamental analysis" have been calculated to accompany the Cash Flow Reconciliation

- Cash Flow per Share
- Share Price to Cash Flow Multiple
- Debt to Cash Flow Ratio
- Debt to Equity Ratio
- Earnings per Share
- Rate of Return on Shareholders' Equity

Per share amounts for 2004 utilize the weighted average number of common shares outstanding of 59,755 480

Cash Flow

Paramount calculates its cash flow

- net of all lease rentals of both producing and non-producing properties
- net of all cash general and administrative costs
- net of all marketing costs which are currently expensed
- net of all interest expenses, none of which are capitalized

Net Earnings

Paramount further calculates its net earnings,

- net of dry hole costs
- net of geological and geophysical costs

CASH FLOW RECONCILIATION

($ millions) December 31	2004	2003	2002	2001	2000
Gross revenue [1]	549.9	379.9	473.9	528.4	391.5
Net royalties [2]	(105.1)	(82.5)	(74.4)	(99.7)	(80.6)
Net revenue	444.8	297.4	399.5	428.7	310.9
Expenses					
Operating	95.8	81.2	86.1	61.1	48.0
Cash G&A	25.2	19.1	15.9	12.4	9.7
Lease rentals	3.5	3.6	4.6	4.3	5.2
Cash interest	24.1	19.0	23.9	19.3	22.3
Bad debt expense (recovery)	(5.5)	6.0	–	–	–
Current income taxes and other	6.8	2.7	9.1	27.7	2.3
Discontinued operations	(0.7)	(1.5)	–	–	–
Cash flow	295.6	167.3	259.9	303.9	223.4

(1) Includes realized financial instrument gains and losses on sale of investments, and net of transportation

(2) Net of ARTC

CASH FLOW AND CASH FLOW/SHARE

Fiscal year	Cash Flow ($ 000s)	Trend [1]	Shares [2] (000s)	Cash Flow per Share ($)	Trend [1]
2000	223,446	100	59,454	3.76	100
2001	303,937	136	59,454	5.11	136
2002	259,916	116	59,458	[illegible]	116
2003	167,276	75	60,098	2.78	74
2004	295,566	132	59,755	4.95	132

(1) Trend with base year 2000, with a nominal value of 100.

(2) Weighted average shares outstanding

SHARE PRICE TO CASH FLOW MULTIPLE

Fiscal Year	Share Low	Price ($) High	Cash Flow per Share ($)	Multiple Low	Multiple High
2000	10.50	20.00	3.76	2.8x	5.3x
2001	12.00	18.75	5.11	2.3x	3.7x
2002	13.00	17.60	4.37	3.0x	4.0x
2003	8.51	16.95	2.78	3.1x	6.1x
2004	10.50	27.00	4.95	2.1x	5.5x

NET DEBT TO CASH FLOW RATIO

Fiscal year	Net Debt ($ 000s)	Cash Flow ($ 000s)	Debt/cash Flow Ratio	Flow Trend [1]
2000	292,360	223,446	1.3:1	100
2001	290,698	303,937	1.0:1	73
2002	555,243	259,916	2.1:1	163
2003	297,055	167,276	1.8:1	136
2004	451,187	295,566	1.5:1	117

(1) Trend with base year 2000 with a nominal value of 100

DEBT TO EQUITY RATIO

Fiscal Year	Operating Debt ($ 000s)	Shareholders' Equity ($ 000s)	Debt/ Equity Ratio	Trend
2000	315,000	418,254	0.75:1	100
2001	316,600	535,384	0.59:1	79
2002	539,270	546,105	0.99:1	131
2003 [2]	287,237	496,033	0.60:1	77
2004 [2]	459,141	625,039	0.73:1	98

(1) Trend with base year 2000 with a nominal value of 100

(2) Excludes discontinued operations

EARNINGS PER SHARE

Paramount's earnings are net of dry hole costs, geological/ geophysical costs and all lease rentals

Fiscal year	Net Earnings ($ 000s)	Trend [1]	Shares [2] (000s)	Net Earnings per Share ($)	Trend
2000	86,062	100	59,454	1.45	100
2001	118,902	138	59,454	2.00	138
2002	10,307	12	59,458	0.17	12
2003	1,151	1	60,098	0.02	1
2004	41,174	48	59,755	0.69	48

(1) Trend with base year 2000 with a nominal value of 100

(2) Weighted average shares outstanding

RATE OF RETURN ON SHAREHOLDER'S EQUITY

Paramount has earned a weighted average after-tax rate of return of 11.5 percent as computed on a book basis, based upon the weighted average shareholders' equity invested over the past five years

($ thousands)	2004	2003	2002	2001	2000
Net earnings	41,174	1,151	10,307	118,902	86,062
Weighted average Shareholders' equity	560,536	521,069	540,745	476,819	373,623
After-tax rate of return (%)	7.3	0.2	1.9	24.9	23.0

UNDEVELOPED LAND

(thousands of acres)	Gross	Net
Alberta	2,190	1,649
British Columbia	348	258
Saskatchewan	17	13
Northwest Territories	1,235	661
Montana, North Dakota	102	39
Other	1,644	822
Total Undeveloped Land	5,536	3,442

Net land	2004	2003
Proved	**640**	586
Undeveloped	**3,442**	2,800
Total net land	**4,082**	3,386
Appraised value of undeveloped land [1]	**$ 185.4**	$ 98.2

(1) Millions of dollars

Appraised value is an estimate of the fair market value of acreage based upon current analogous sales Approximately 84 percent of the total net 2004 land inventory of 4.1 million acres is undeveloped

OIL & GAS SALES AND GROSS PROFIT

This illustrates oil and gas sales since 2000 and converts the oil sales into barrels of equivalent on the basis of one barrel of crude oil/liquids equals 6 Mcf of natural gas

Fiscal year	P&NG Revenue (after financial instruments and transportation costs) ($ 000s)	Trend	Oil & Liquids Gas Production (MMcf)	Trend	Production (Boe)	Trend	Average Price (after realized financial instruments) Gas ($)	Oil ($)	Barrel of Equivalent Production (MBoe)	Trend
2000	391,470	100	80,520	100	574,986	100	4.59	37.80	13,995	100
2001	525,686	134	82,125	102	790,225	137	6.12	35.48	14,478	103
2002	431,001	110	88,111	109	2,066,995	359	4.08	34.64	16,753	120
2003	380,855	97	55,760	69	2,616,706	455	5.76	35.50	11,910	85
2004	569,309	145	63,360	79	2,670,794	464	6.86	44.13	13,231	95

(1) Trend with base year 2000, with nominal value of 100.

OPERATING CASH NETBACKS

Fiscal Year	Royalties (net ARTC) ($ 000s)	($/Boe)	Trend	Operating Costs $ 000s	($/Boe)	Trend	Operating Cash Netback ($ 000s)	($/Boe)	Trend	% of Revenue
2000	80,541	5.75	100	47,974	3.43	100	262,955	18.79	100	67.2
2001	99,706	6.89	124	61,045	4.22	127	351,814	24.29	129	66.9
2002	74,444	4.44	92	86,067	5.14	179	266,618	15.92	85	61.9
2003	82,512	6.93	102	81,193	6.82	169	269,334	22.60	120	70.7
2004	105,046	7.94	130	95,767	7.24	200	349,769	26.44	141	61.4

(1) Trend with base year 2000, with nominal value of 100.
(2) Operating cash netback = oil & gas and other revenue – royalty – operating cost

REVENUE/EXPENSES/CASH FLOW NETBACK/NET EARNINGS

The table calculates revenue, expenses and net earnings converted into dollars per thousand cubic feet gas equivalent (1 barrel = 6 Mcf)

($/Boe)	2004	2003	2002	2001	2000
Annual production (MBoe)	**13,231**	11,910	16,753	14,478	13,995
Gross revenue before financial instruments, net of transportation	**$ 41.61**	$ 36.45	$ 23.06	$ 35.20	$ 27.97
Gain (loss) on sale of investments	–	(0.09)	2.44	0.20	–
Royalties	**(7.94)**	(6.93)	(4.44)	(6.89)	(5.75)
Operating costs	**(7.24)**	(6.82)	(5.14)	(4.22)	(3.43)
Operating netback	**26.43**	22.61	15.92	24.29	18.79
Realized financial instruments gain (loss)	**(0.05)**	(4.47)	2.79	1.09	–
General and administrative	**(1.91)**	(1.60)	(0.95)	(0.85)	(0.69)
Bad debt recovery (expense)	**0.42**	(0.50)	–	–	–
Cash interest	**(1.82)**	(1.60)	(1.43)	(1.33)	(1.59)
Lease rentals	**(0.27)**	(0.30)	(0.27)	(0.30)	(0.27)
Current income tax	–	–	–	(1.73)	–
Large corporation tax and other	**(0.51)**	(0.23)	(0.55)	(0.19)	(0.16)
Other	**0.05**	0.13	–	–	–
Cash flow netback	**22.34**	14.04	15.51	20.98	15.98
Unrealized financial instrument gain (loss)	**1.46**	–	–	–	–
Stock based compensation expense	**(3.11)**	(0.10)	(0.02)	–	–
Non-cash interest	**(0.10)**	(0.01)	–	–	–
Depletion and depreciation	**(14.48)**	(13.86)	(10.11)	(7.28)	(3.61)
Accretion of asset retirement obligations	**(0.52)**	(0.34)	(0.21)	(0.17)	(0.12)
Surmont compensation	–	–	2.23	–	–
Gain (loss) on sale of properties	**1.23**	(0.31)	–	(0.11)	0.05
Dry hole costs	**(1.87)**	(3.07)	(7.17)	(0.62)	(0.50)
Write-down of petroleum and natural gas properties	–	(0.87)	(1.87)	–	–
Geological and geophysical	**(0.66)**	(0.71)	(0.56)	(0.74)	(0.48)
Unrealized foreign exchange gain on US debt	**1.83**	0.13	–	–	–
Realized foreign exchange gain on US debt	**0.54**	–	–	–	–
Premium on redemption of US debt	**(0.90)**	–	–	–	–
Other	**0.42**	(0.13)	–	–	–
Future income taxes recovery (expense)	**(3.07)**	5.33	2.30	(3.87)	5.14
Net earnings	**$ 3.11**	$ 0.10	$ 0.60	$ 8.19	$ 6.18
Net earnings trend [1]	**50**	2	10	133	100

(1) Trend with base year 2000, with nominal value of 100.

HISTORICAL SUMMARY

	2004	2003	2002	2001	2000
Gas production (MMcf/d)	**173.1**	152.8	241.4	225.0	220.0
Crude oil and liquids production (Bbl/d)	**7,297**	7,169	5,663	2,165	1,571
Gas proved reserves (Bcf)	**568.6**	241.7	446.5	437.7	518.1
Crude oil and liquids proved reserves (MBbl)	**20,461**	10,617	17,545	6,339	4,709
Total proved and probable reserves (MMBoe) 6:1	**115.2**	67.4	125.9	101.9	115.5
Cash flow ($ millions)	**$ 295.6**	$ 167.3	$ 259.9	$ 303.9	$ 223.4
Cash flow per share (basic)	**$ 4.95**	$ 2.78	$ 4.37	$ 5.11	$ 3.76
Net earnings ($ millions)	**$ 41.2**	$ 1.1	$ 10.3	$ 118.9	$ 86.1
Net earnings per share (basic)	**$ 0.69**	$ 0.02	$ 0.17	$ 2.00	$ 1.45

Paramount resources ltd.

ANALYST SUPPLEMENT

This handbook has been prepared by Paramount Resources Ltd. to address the special information needs of the investment community and the sophisticated investor. The handbook provides detailed performance data and key ratios. For additional information please contact:

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Paramount Resources Ltd.
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Calgary, Alberta, Canada T2P 5C5
Tel (403) 290-3600 Fax (403) 262-7994 www.paramountres.com

CORPORATE PROFILE

Paramount Resources Ltd. is a Canadian energy company with its revenue derived primarily from natural gas sales. The Company explores for, develops, produces and markets natural gas, crude oil and natural gas liquids. Paramount has an aggressive, focused exploration and development strategy, concentrated on acquiring land and establishing reserves throughout the Western Canadian Sedimentary Basin.

- 26 years old
- 277 employees (171 head office, 106 field)
- Listed on the Toronto Stock Exchange, symbol "POU"
- Part of the S&P/TSX Composite Index
- 63.2 million shares outstanding at December 31, 2004
- Market capitalization: $1.7 billion (December 31, 2004)

Year	Cash Flow	Basic per Share	Earnings	Basic per Share
2002	$ 259.9 million	$ 4.37	$ 10.3 million	$ 0.17
2003	$ 167.3 million	$ 2.78	$ 1.1 million	$ 0.02
2004	$ 295.6 million	$ 4.95	$ 41.2 million	$ 0.69

Average number of common shares outstanding for 2004 was 59.8 million.

UNIQUE TRAITS

- 80 percent of 2004 production is natural gas.
- "Successful efforts" accounting policy results in conservative net earnings.
- High management ownership (53 percent).
- Successful full cycle exploration and development creates shareholder value.
- Proven performance record through 26 years of commodity price cycles.
- Exposure to high impact exploration plays in Colville Lake and Northeast Alberta bitumen project.

CONSOLIDATED EARNINGS & CASH FLOW DATA

($ millions except per share amounts)

Year ended December 31	2004	2003	Change (%)
Revenue			
Natural gas, net of transportation	**$ 425.6**	$ 333.9	27
Crude oil and liquids, net of transportation	**124.9**	100.1	25
Gain (loss) on financial instruments	**18.7**	(53.2)	(135)
Royalties (net of Alberta Royalty Tax Credit)	**(105.0)**	(82.5)	27
Loss on sale of investments	-	(1.0)	(100)
Net revenue	**464.2**	297.3	56
Expenses			
Operating	**95.8**	81.2	18
Interest	**25.4**	19.2	32
General and administrative	**25.2**	19.1	32
Stock based compensation expense	**41.2**	1.2	3,333
Bad debt expense (recovery)	**(5.5)**	6.0	(192)
Lease rentals	**3.5**	3.6	(3)
Geological and geophysical	**8.7**	8.5	2
Dry hole costs	**24.7**	36.6	(33)
(Gain) loss on sales of property land and equipment	**(16.3)**	3.6	(553)
Accretion of asset retirement obligations	**6.9**	4.0	73
Depletion and depreciation	**191.6**	165.1	16
Write-down of petroleum and natural gas properties	-	10.4	(100)
Unrealized foreign exchange gain on US debt	**(24.2)**	(1.6)	1,413
Realized foreign exchange gain on US debt	**(7.2)**	-	-
Premium on redemption of US debt	**12.0**	-	-
Large Corporation Tax and other	**6.8**	2.7	152
Future income tax (recovery) expense	**40.7**	(63.5)	(164)
	429.3	296.1	45
Net earning from continuing operations	**34.9**	1.2	2,808
Net earnings (loss) from discontinued operations	**6.3**	(0.1)	(6,400)
Net earnings	**$ 41.2**	**$ 1.1**	**3,645**
Net earnings per common share - basic	**$ 0.69**	**$ 0.02**	**3,350**

CASH FLOW RECONCILIATION

($ millions)

Year ended December 31	2004	2003
Net revenue [1]	**444.8**	297.4
Operating costs	**(95.8)**	(81.2)
Interest on long-term debt (excluding non-cash interest)	**(24.1)**	(19.0)
General and administrative	**(25.2)**	(19.1)
Bad debt recovery (expense)	**5.5**	(6.0)
Lease rentals	**(3.5)**	(3.6)
Current and Large Corporation Tax	**(6.8)**	(2.7)
Cash flow from continuing operations	**249.9**	165.8
Cash flow from discontinued operations	**0.7**	1.5
Cash flow from operations	**295.6**	167.3
Cash flow per common share – basic	**4.95**	2.78

(1) Net of realized financial instrument gains and losses, royalties, transportation costs, and gains on sale of investments

COMPANY FORECAST 2005

Production / Pricing	
Gas (MMcf/d) ($/Mcf)	210 @ $ 6.50
Oil/liquids (Bbl/d) ($/Bbl)	10,000 @ US$ 42.00
Cash flow ($MM)	425
Cash flow per share	6.66
Capital budget ($MM)	340

COMMON SHARE DATA

Shares of Paramount Resources Ltd. trade on The Toronto Stock Exchange under the symbol "POU" (Oil and Gas Producers sub-index) and is part of the S&P/TSX Composite Index.

At December 31	2004	2003
Outstanding shares (000s)	**63,186**	60,095
Public float [1] – shares (000s)	**29,697**	27,818
– % of total shares	**47%**	46%
Trading volume (000s)	**38,489**	34,335
Trading value (000s)	**$ 719,743**	$ 431,533
Trading range		
High	**$ 27.90**	$ 16.95
Low	**$ 10.41**	$ 5.51
Close	**$ 26.90**	$ 10.45
Weighted average trading price	**$ 18.70**	$ 12.57
Market capitalization at year end ($ millions)	**1,700**	$ 628.0

(1) Public float is all outstanding shares less shares owned/controlled by officers/directors.

DIRECTORS AND OFFICERS

C.H. (Clay) Riddell [3]
Director, Chairman and Chief Executive Officer

B.K. (Bernard) Lee
Chief Financial Officer

J.H.T. (Jim) Riddell
Director, President and Chief Operating Officer

C.E. (Chuck) Morin
Corporate Secretary

L.M. (Lloyd) Doyle
Corporate Operating Officer

C.G. (Cal) Folden
Corporate Operating Officer

J.S. (Scott) McDougall
Corporate Operating Officer

G.W.P. (Geoff) MacMillan
Corporate Operating Officer

E. (Ed) Williams
Corporate Operating Officer

L.A. (Laurel) Friesen
Assistant Corporate Secretary

J.C. (John) Gorman [1,4]
Director

D. (Dirk) Junge, C.F.A.
Director

D.M. (David) Knott
Director

W.B. (Wally) MacInnes, Q.C.
Director

V.S.A. (Vi) Riddell
Director

S.L. (Sue) Riddell Rose
Director

J.B. (John) Roy [1,2,3,4]
Director

A.S. (Alistair) Thomson
Director

B.M. (Bernie) Wylie
Director

(1) Member of Audit Committee
(2) Member of Environmental, Health and Safety Committee
(3) Member of Compensation Committee
(4) Member of Corporate Governance Committee

FIVE-YEAR SHARE PRICE AND TRADING VOLUME


TRILOGY
ENERGY TRUST

Trilogy Energy Trust [1] (TET.UN): is a Canadian energy trust formed through the spinout of a portion of Paramount Resources assets in the Kaybob and Marten Creek areas of central Alberta. These assets are primarily low-risk, high working interest, lower-decline properties that are geographically concentrated with many infill drilling opportunities, good access to infrastructure and processing facilities that are operated and controlled by the Trust. By operating the wells and production infrastructure, we can control two variables that affect the cash flow and revenues of the Trust.

The Trust will employ a strategy to provide Unitholders with: a competitive annual yield by making monthly cash distributions to Unitholders, maintain the Trilogy assets at a level that provides stable production, and continue to expand the business of the Trust through the development of growth opportunities that will provide long-term stable cash flows.

The technical expertise that has been employed at Paramount will continue to develop and exploit the land and reserves in Kaybob and Marten Creek. The field operation has been growing and developing the operational expertise to operate effectively and efficiently in the Kaybob area and will continue to be an intregal part of the exploitation and production of the assets. The Trust's infill drilling opportunities and large undeveloped land base are expected to make it less reliant on the acquisition market to maintain distributions. The management of Trilogy Energy Ltd., the Administrator of the Trust, will consider strategic asset acquisitions that would be accretive to the production, reserves and cash flow of the Trust and provide undeveloped potential that can be exploited to increase the value of the Trust.

(1) References to the Trust in this summary include, where the context requires, the trusts, corporations and partnerships directly or indirectly owned by the Trust.


MARTEN
CREEK
EAST
KAYBOB

Letter to Unitholders

Paramount's management continually reviews all options available to it to ensure that Paramount's capital structure is efficient and that shareholder value is being enhanced. In this regard, in 2004, certain senior management of Paramount conducted a preliminary review of possible restructuring alternatives available to Paramount to increase shareholder value. The Board of Directors, after considering the alternatives presented to it and after receiving advice from its legal and financial advisors, approved a reorganization of a portion of Paramount's assets into an energy trust (the "Trust Spinout").

The Benefits of Forming the Trust

Paramount believes the Trust Spinout will enhance value for shareholders by dividing Paramount's assets into two specific groups, consisting of: (i) the higher free cash flow Kaybob and Marten Creek assets which will be owned through the Trust, which will pay regular cash distributions; and (ii) the predominantly growth oriented assets which will continue to be owned by Paramount. The Trust Spinout will allow shareholders to participate, either separately or on a combined basis, in the growth potential and mature qualities of Paramount's assets. Paramount believes that the post transaction structure better aligns risks and returns from each asset class in a way that is both sustainable and tax effective. This new structure should provide greater aggregate access to capital to fund the growth of the businesses of each of Paramount and the Trust; and a more active and liquid market for the new Common Shares and the Trust Units.

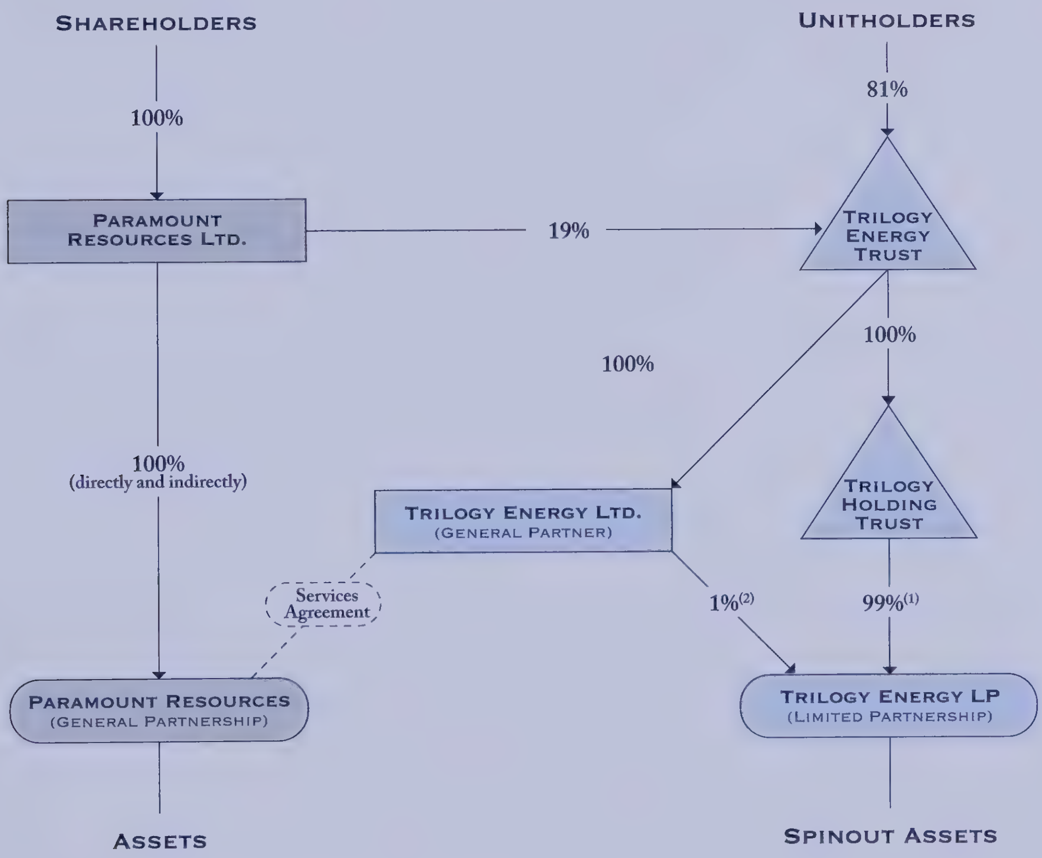
The Process of Restructuring

In order to implement any proposed reorganization of Paramount, Paramount required the consent of the majority of the holders of each of its 7 7/8% Notes due 2010 and its 8 7/8% Notes due 2014. On February 7, 2005, Paramount obtained consent from the note holders and completed, as amended, the Notes Offer issuing U.S.$213,593,000 principal amount of 8 1/2% Notes due 2013 and paying aggregate cash consideration of approximately U.S.$36.2 million in exchange for approximately 99.31% of the outstanding 2010 Notes and 100% of the outstanding 2014 Notes. This cleared the way to continue with the Trust Spinout.

The Plan

The Trust Spinout resulted in the shareholders receiving one new Paramount Resources Ltd. Common Share and one Unit of the Trust in exchange for each Paramount Resources Ltd. Common Share held. Upon completion of the Trust Spinout, Paramount shareholders owned 100 percent of post-reorganization Paramount and 81 percent of the outstanding units of Trilogy. Paramount owned the remaining 19 percent of the outstanding units of the Trust. Through Trilogy, the unitholders will receive regular monthly cash distributions from the cash flow produced by the Trust's developed assets. Through Paramount, shareholders will participate in the potential upside of Paramount's remaining predominately growth-oriented assets.

The following diagram illustrates the organizational structure of Paramount Resources Ltd. and Trilogy Energy Trust:



Notes:

1) Limited Partnership interest.
2) General Partnership interest. The General Partner's interest may be reduced, and Holding trust's interest may be increased, pursuant to post-Arrangement transactions.

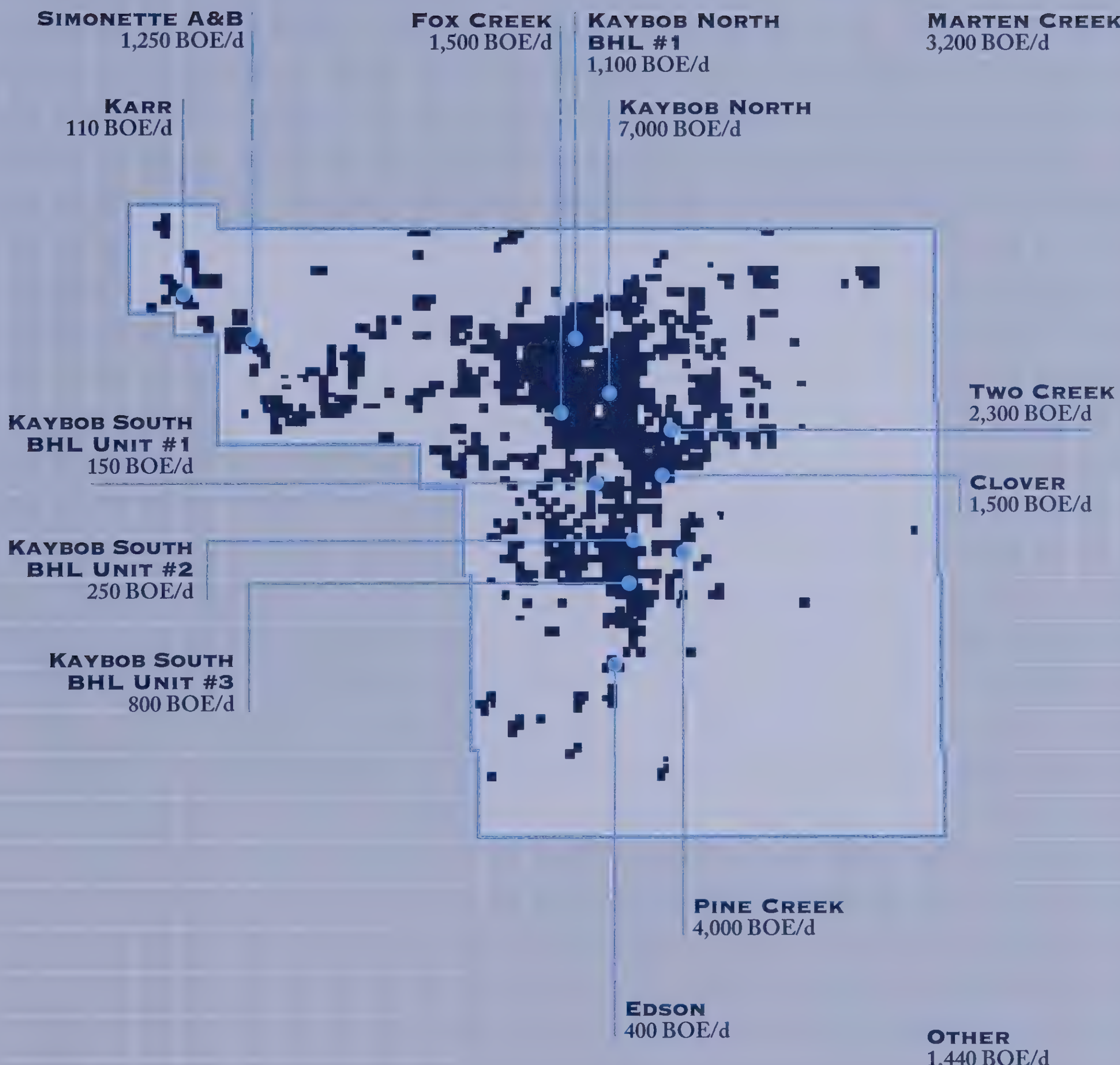
The Assets

The East Kaybob and Marten Creek properties held by Trilogy Energy Trust are geographically concentrated in central Alberta. These are developed, high working interest, lower decline properties with many infill drilling opportunities and good access to owned infrastructure and processing facilities. The Trilogy assets are currently producing approximately 25,000 Boe/d, comprised of approximately 120 MMcf/d of natural gas and 5,000 Bbl/d of crude oil and natural gas liquids. A report of Paddock Lindstrom & Associates Ltd., independent petroleum engineers, dated effective December 31, 2004 assigned 44,722 MBoe of Proved Reserves and 64,254 MBoe of Proved plus Probable Reserves to these properties.

The East Kaybob properties represent approximately 89 percent of the production and 93 percent of the Proved plus Probable Reserves of the Trust Spinout assets as at December 31, 2004. The production at the end of March 2005 averaged approximately 22,200 Boe/d (approximately 103 MMcf/d of natural gas and 5,000 Bbl/d of crude oil and natural gas liquids). The natural gas produced from the East Kaybob area is typically liquid-rich with a high heat content which translates into a premium price relative to AECO gas. The Paddock Lindstrom report has assigned 41,714 MBoe of Proved Reserves and 60,008 MBoe of Proved plus Probable Reserves to this area. The assets in East Kaybob also include, as at December 31, 2004, 356,927 (333,203 net) developed acres and 373,362 (206,558 net) undeveloped acres of land.

This area is known for its multi-zone potential. The wells in this area produce from the Viking, Spirit River, Bluesky, Gething, Nordegg, Montney and Swan Hills formations which have well depths between 1,500 to 3,500 metres. Approximately 58 percent of the natural gas production from these properties will be processed at three Trilogy-operated natural gas plants with an average 75 percent working interest. Approximately 64 percent of the oil and natural gas liquids production in this area is treated at Trilogy-operated oil batteries with an average working interest of 65 percent.

The Marten Creek property represents approximately 11 percent of the production and 7 percent of the Proved plus Probable Reserves attributable to the Trust Spinout assets as at December 31, 2004. The production at the end of March 2005 averaged approximately 17 MMcf/d of natural gas or approximately 2,800 Boe/d. The Paddock Lindstrom report has assigned 3,008 MBoe of Proved Reserves and 4,246 MBoe of Proved plus Probable Reserves to this area. As at December 31, 2004 Marten Creek had 26,880 (26,880 net) developed acres and 117,120 (115,200 net) undeveloped acres of land. The wells in this area produce primarily from the Viking, Clearwater and Wabiskaw formations which have well depths of between 300-500 metres. The main gathering system and processing plant in Marten Creek is operated by a midstream processing company.


SIMONETTE A&B
1,250 BOE/d
FOX CREEK
1,500 BOE/d
KAYBOB NORTH
BHL #1
1,100 BOE/d
MARTEN CREEK
3,200 BOE/d
KARR
110 BOE/d
KAYBOB NORTH
7,000 BOE/d
TWO CREEK
2,300 BOE/d
KAYBOB SOUTH
BHL UNIT #1
150 BOE/d
CLOVER
1,500 BOE/d
KAYBOB SOUTH
BHL UNIT #2
250 BOE/d
KAYBOB SOUTH
BHL UNIT #3
800 BOE/d
PINE CREEK
4,000 BOE/d
EDSON
400 BOE/d
OTHER
1,440 BOE/d

The People

Dedicated Paramount staff involved in the development and implementation of the technical fundamentals responsible for the successful exploitation of the Trust assets will continue their employment with Trilogy, employed by Trilogy Energy LP. The management will consider strategic asset acquisitions that would be accretive to the production, reserves and per unit cash flow of the Trust and provide undeveloped potential that can be exploited to add additional value.

The field operation has been growing and developing the operational expertise to operate effectively and efficiently in the Kaybob area and will continue to be a part of the exploitation and production of the assets. The Trust will ensure that the field employees are trained, qualified and sufficiently experienced to perform the assigned task in a competent manner.

It is the tenet of the Trust to create a corporate culture that attracts and rewards employees who are passionate, innovative and inspired to add to the value of the Trust. The Trust culture will support continuous improvement, resulting in better performance and more free cash flow for distributions.

The Outlook

The success of Trilogy Energy Trust will be contingent on the implementation of a strategy that will result in a stable production profile, provide steady cash flow and ultimately, stable distributions for unitholders. We are excited to go forward with a capital program to replace reserves and production. The assets will provide a growth platform for successful ongoing development of this tight gas resource play. We are confident in the vast array of currently identified development opportunities. There exists a large, as yet, undeveloped resource in the central Alberta area that will fuel future growth and add tremendous value for Trilogy Unitholders and Paramount Shareholders.

The first monthly distribution of the Trust is targeted to occur on May 15, 2005 to unitholders of record on May 2, 2005. Successful production replacement, prudent asset management, strong commodity prices and continued efficient control of operations will support a stable distribution. We are confident in our management, our high quality assets and our proven expertise. We believe the Trust will be a rewarding investment for our unitholders.

Jim Riddell
President & Chief Executive Officer

Officers and Directors of Trilogy Energy Ltd., the Administrator of the Trust

OFFICERS

J. H. T. Riddell
President and Chief Executive Officer

B. K. Lee
Chief Financial Officer

J. B. Williams
Chief Operating Officer

C. E. Morin
Corporate Secretary

DIRECTORS

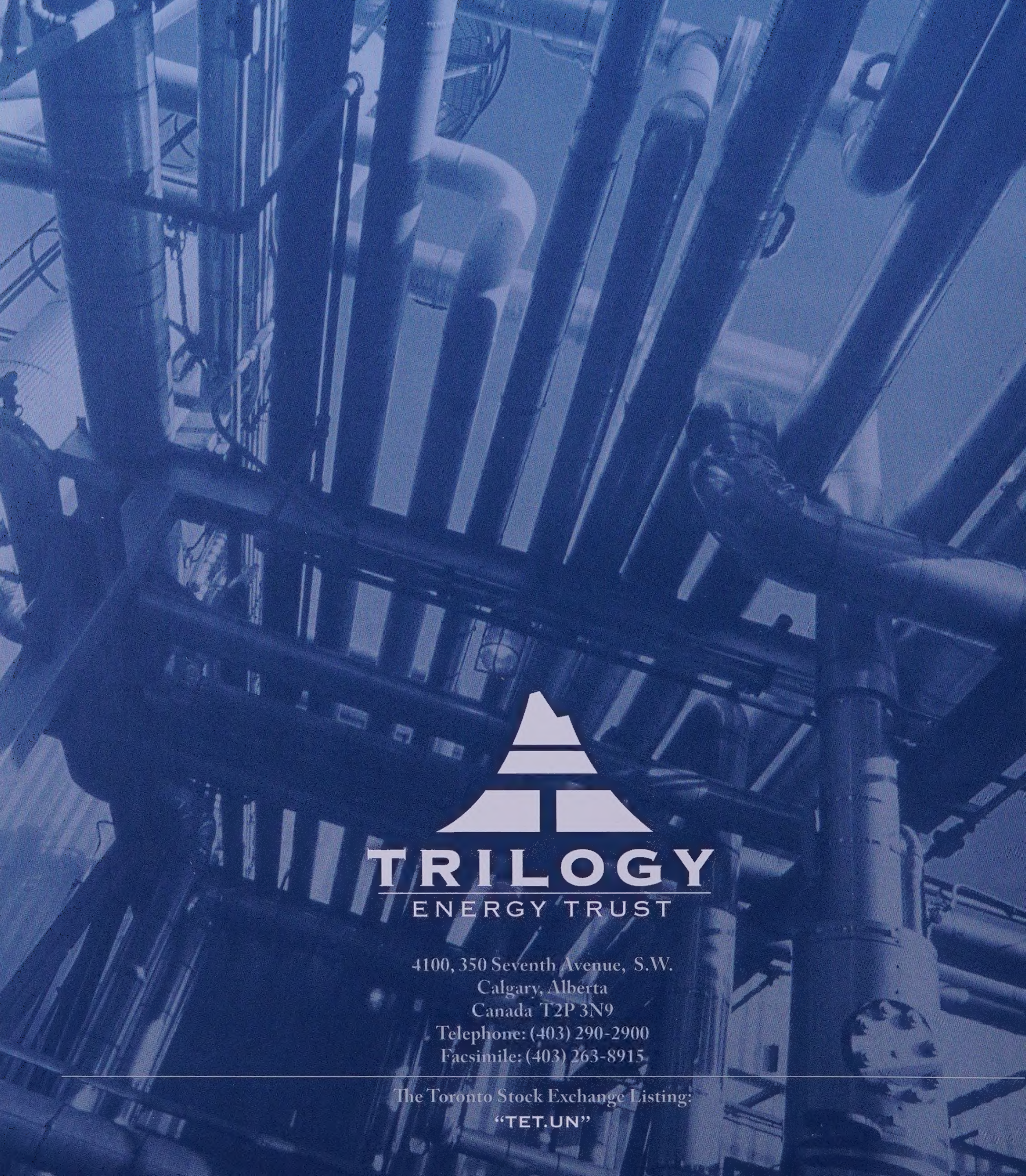
C. H. Riddell
Non Executive Chairman of the Board
Calgary, Alberta

J. H. T. Riddell
President and Chief Executive Officer
Calgary, Alberta

R.M. MacDonald
Independent Businessman
Calgary, Alberta

D.F. Textor
Retired
Locust Valley, New York

E.M.Shier
Partner Heenan Blaikie LLP
Calgary, Alberta



TRILOGY
ENERGY TRUST

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The Toronto Stock Exchange Listing:
"TET.UN"

ABBREVIATIONS

Bbl	barrels
Bbl/d	barrels per day
Bcf	billion cubic feet
Bcfe	billion cubic feet of gas equivalent
Boe	barrels of oil equivalent
GJ	gigajoules
GJ/d	gigajoules per day
Mcf	thousand cubic feet
Mcfe	thousand cubic feet of gas equivalent
Mcf/d	thousand cubic feet per day
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MBbl	thousands of barrels
MMbtu	millions of British Thermal Units
MBoe	thousands of barrels of oil equivalent
MMcfe/d	million cubic feet of gas equivalent per day

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